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**BEFORE THE**
**PUBLIC UTILITIES COMMISSION**
**OF THE STATE OF CALIFORNIA**

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| Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development of, California Renewables Portfolio Standard Program. | Rulemaking 15-02-020 (Filed February 26, 2015) |

# PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) AUGUST 4, 2015 DRAFT RENEWABLE ENERGY PROCUREMENT PLAN

**(PUBLIC VERSION)**

**[Redaction in Plan and Appendices A, B, C, D, F and H]**

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Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: August 4, 2015

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**OF THE STATE OF CALIFORNIA**

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**AUGUST 4, 2015 DRAFT RENEWABLE ENERGY PROCUREMENT PLAN**

**(PUBLIC VERSION)**

**[Redaction in Plan and Appendices A, B, C, D, F and H]**

In compliance with the *Assigned Commissioner's Revised Ruling Identifying Issues and Schedule of Review for 2015 Renewables Portfolio Standard Procurement Plans*, issued on May 28, 2015 ("ACR"), Pacific Gas and Electric Company ("PG&E") hereby files its 2015 Draft Renewable Energy Procurement Plan (the "2015 RPS Plan"). Consistent with the ACR, PG&E has included in its filing both clean and redlined versions of the 2015 RPS Plan, with the redline showing changes from the Final 2014 RPS Plan filed on December 23, 2014, wherever applicable.

Respectfully submitted,


CHARLES R. MIDDLEKAUFF
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By: *<u>/s/ Charles R. Middlekauff</u>*
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Dated: August 4, 2015

# VERIFICATION

I, Stephanie Greene, am an employee of PACIFIC GAS AND ELECTRIC COMPANY, a corporation, and am authorized to make this verification on its behalf. I have read the foregoing **PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) AUGUST 4, 2015 DRAFT RENEWABLE ENERGY PROCUREMENT PLAN (PUBLIC VERSION)** dated August 4, 2015.

The statements in the foregoing document are true to my own knowledge, except as to matters which are therein stated on information and belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on this 28th day of July 2015 at San Francisco, California.

*/s/ Stephanie Greene*
**Stephanie Greene**
Manager, Renewable Energy
Pacific Gas and Electric Company

# Public

PACIFIC GAS AND ELECTRIC COMPANY

RENEWABLES PORTFOLIO STANDARD

2015 RENEWABLE ENERGY PROCUREMENT PLAN (DRAFT VERSION)

AUGUST 4, 2015

# Public

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Pacific Gas and Electric Company ("PG&E") respectfully submits its 2015 Renewables Portfolio Standard ("RPS") Plan to the California Public Utilities Commission ("CPUC" or "Commission") as directed by the Assigned Commissioner in this proceeding in the *Assigned Commissioner's Revised Ruling Identifying Issues and Schedule of Review for 2015 Renewable Portfolio Standard Procurement Plans* ("ACR") issued on May 28, 2015. PG&E's 2015 RPS Plan includes a summary of key issues and important legislative and regulatory developments impacting California's RPS requirements, and then addresses each of the specific requirements identified in the ACR.[1] PG&E believes its 2015 RPS Plan satisfies all of the statutory and Commission requirements and addresses key policy issues that have arisen as the renewable energy industry matures and grows in California.

# 1 Summary of Key Issues

## 1.1 PG&E's RPS Position

PG&E projects that under both the current 33% RPS by 2020 target, as well as a 40% by 2024 scenario, it is well-positioned to meet its RPS compliance requirements for the second (2014-2016) and third (2017-2020) compliance periods and will not have incremental procurement need until at least 2022. Under the current 33% RPS target, PG&E projects that it will have incremental procurement need beginning in [redacted], after applying banked volumes of excess procurement ("Bank") beginning in [redacted]. Under the 40% RPS by 2024 scenario, PG&E projects that it will have incremental procurement need beginning in [redacted], after applying Bank beginning in [redacted]. In both situations, PG&E anticipates additional steady, incremental long-term procurement in subsequent years to avoid the need to procure large volumes in any single year to meet compliance needs and maintain minimum Bank levels.

1 *See* ACR, pp. 8-20.

### 1.2 PG&E Proposes Not to Hold a Request for Offers in 2015

Given its current RPS compliance position, PG&E proposes not to hold an RPS solicitation in 2015. PG&E has sufficient time in the coming years to respond to changing market, load forecast, or regulatory conditions and will reassess the need for future solicitations in next year's RPS Plan. Although many factors could change its RPS compliance position, PG&E believes that its existing portfolio of executed RPS contracts, its owned RPS-eligible generation, and its expected Bank balances will be adequate to ensure compliance with near-term RPS requirements. Additionally, PG&E expects to procure additional volumes of incremental RPS-eligible contracts through mandated procurement programs in 2016.[2] In 2016, PG&E will reassess its Renewable Net Short ("RNS") position and determine its updated procurement needs. PG&E's proposal not to hold a 2015 RPS solicitation is consistent with a proposal made by San Diego Gas & Electric Company ("SDG&E") in its 2014 RPS Plan, and approved by the Commission given SDG&E's lack of need.[3]

### 1.3 Consideration of Higher RPS Targets Should Be Integrated With Broader State Greenhouse Gas Goals

California's RPS has played, and will continue to play, an important role in lowering electric sector greenhouse gas ("GHG") emissions and meeting the state's clean energy goals. PG&E supports maintaining the existing requirements that load-serving entities ("LSE") provide a minimum of 33% RPS in 2020 and beyond. As the state looks beyond 2020, however, PG&E believes California's clean energy policy should be centered on achieving the most cost-effective GHG reductions needed to meet the Governor's 2030 goal of emissions that are 40% of 1990 levels.[4]

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2 Mandated programs include Renewable Auction Mechanism ("RAM"), Renewable Market Adjusting Tariff ("ReMAT"), and Bioenergy Market Adjusting Tariff ("BioMAT"). In addition, while not pursuant to the RPS mandate, PG&E expects to procure additional volumes over the next year for the Green Tariff Shared Renewables Program ("GTSR").

3 Decision ("D.") 14-11-032, p. 32, Ordering Paragraph ("OP") 17.

4 Office of California Governor Edmund G. Brown, Executive Order 4-29-2015 (available at http://gov.ca.gov/news.php?id=18938).

Before taking any action that would increase the RPS requirements, the Commission should consider how the RPS program fits within a comprehensive GHG policy framework built to achieve emissions reductions through a combination of actions, as opposed to potentially inefficient carve-out mechanisms.[5] Renewable energy policy should be more completely aligned with this broader policy context in order to ensure that GHG reduction targets are achieved in an integrated and economically efficient manner. Rather than reflexively raise the RPS targets, the CPUC should adopt a strategy focused on flexibility, equitable rules for all LSEs, affordability, and market and system stability.[6]

### 1.4 Renewable Portfolio Growth Increases Customer Rate Impacts

As a part of this RPS Plan, PG&E is providing historic and forecasted RPS cost and rate information. From 2003-2015, PG&E's annual RPS-eligible procurement and generation costs have continued to increase. The costs of the RPS Program have already and will continue to impact customer bills. From 2003-2016, PG&E estimates its annual rate impact from RPS procurement has increased from 0.7 cents per kilowatt-hour ("¢/kWh") in 2003 to an estimated 3.5¢/kWh in 2016.[7] The growth in rates due to RPS procurement costs will continue to increase through 2020, as the average rate impact is forecasted to increase to 3.9¢/kWh, or approximately $2.3 billion. Further detail regarding RPS costs is provided in Section 13 and the annual rate impact of forecasted procurement is detailed in Table 2 of Appendix D.

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**5** For further discussion of the cost impacts of mandated procurement programs, see Section 13.3.

**6** For further discussion, see PG&E's opening and reply comments in response to *Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program (R.15-02-020)* filed on March 26, 2015 and April 6, 2015, respectively.

**7** "Annual Rate Impact" should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable "premium." In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

To address these rate impacts, PG&E's procurement strategy attempts to minimize cost and maximize value to customers, while satisfying the RPS program requirements. To accomplish this goal, PG&E promotes competitive processes to procure incremental RPS volumes, strategically uses its Bank, and avoids long-term over-procurement.

As described above, a more integrated GHG policy framework that enables LSEs to adapt to changing needs, costs, and circumstances and manage the integration of variable resources would provide additional opportunities to lower customer costs. New technologies will emerge and the mix and cost-effectiveness of GHG emissions reduction strategies will undoubtedly evolve over the next several years. PG&E believes that a more flexible implementation of the RPS Program that allows LSEs to optimize a portfolio of different GHG reduction strategies would facilitate meeting the State's environmental goals at the lowest possible costs and best portfolio fit, and provide the maximum benefits to customers. Similarly, as discussed in Section 13.3, mandated procurement programs within the RPS reduce the program's efficiency while increasing costs.

### 1.5 PG&E's Bank Is Necessary to Ensure Long-Term Compliance

PG&E views its Bank as necessary to: (1) mitigate risks associated with variability in load; (2) protect against project failure or delay exceeding forecasts; and (3) avoid intentional over-procurement above the 33% RPS target by managing year-to-year generation variability from performing RPS resources. The Bank allows PG&E to mitigate the need to procure additional RPS products at potentially high market prices in order to meet near-term compliance deadlines. With an adequate Bank, PG&E aims to minimize customer cost by having the flexibility not to procure in "seller's market" situations. More information on forecasted Bank size and minimum Bank levels under both 33% and 40% RPS is provided in Section 7 below.

PG&E will continue to assess the value to its customers of sales of surplus procurement. Currently, PG&E's RNS, future RPS cost projections, and assessment of the current Renewable Energy Credit ("REC") market do not lead to an expectation of material projected sales of RECs. However, PG&E will consider selling surplus non-bankable RPS volumes and may consider selling surplus bankable volumes if it can still maintain an adequate Bank and if market conditions are favorable.

### 1.6 RPS Rules Should Be Applied Consistently and Equitably Across All LSEs

PG&E's long-term position is a forecast based on a number of assumptions, including a certain amount of load departure due to Community Choice Aggregation ("CCA") and distributed generation growth. While it is possible that this forecasted load departure may not fully materialize or occur at the rate assumed in the forecast, PG&E's forecast is a reasonable scenario based on current trends. Under the existing percentage-based RPS targets, any departure of PG&E's load to CCAs naturally results in both a reduction of PG&E's required RPS procurement quantities and a corresponding increase in RPS procurement by CCAs. Thus, CCAs will be required to shoulder an increasing portion of the State's RPS procurement goals. The consistent and equitable application of all RPS rules and requirements to all Commission-jurisdictional LSEs, including CCAs and Electric Service Providers ("ESPs"), will help to ensure that all LSEs are helping California achieve its ambitious renewable energy goals.

## 2 Summary of Important Recent Legislative/Regulatory Changes to the RPS Program

PG&E's portfolio forecast and procurement decisions are influenced by ongoing legislative and regulatory changes to the RPS Program. The following is a description of recent changes to the RPS Program that have impacted PG&E's RPS procurement.

### 2.1 Commission Implementation of Senate Bill 2 (1x)

Senate Bill ("SB") 2 (1x), enacted in April 2011 and effective as of December 11, 2011, made significant changes to the RPS Program, most notably extending the RPS goal from 20% of retail sales of all California investor-owned utilities ("IOUs"), ESPs, publicly-owned utilities ("POUs"), and CCAs by the end of 2010, to a goal of 33% of retail sales by 2020. The Commission issued an Order Instituting Rulemaking to implement SB 2 (1x) in May 2011 and has subsequently issued a number of key decisions implementing certain “high priority” issues needed to implement the complex provisions of SB 2 (1x). In February 2015, the Commission opened a new rulemaking (R.) 15-02-020 to address remaining issues from this earlier proceeding, as well as other elements of the ongoing administration of the RPS Program. Commission action on remaining and new key issues may impact PG&E’s procurement need and actions going forward, notwithstanding the forecasts and projections included in this Plan.

Key Commission decisions issued to date implementing SB 2 (1x) include D.11-12-052 which defined portfolio content categories (“PCC”), D.11-12-020 which outlined compliance period targets for the 33% RPS target, and D.12-06-038 which implemented changes to the RPS compliance rules for retail sellers, including treatment of prior procurement to meet RPS obligations for both the 20% and 33% RPS Programs. D.12-06-038 also adopted rules on calculating the RPS Bank, meeting the portfolio balance requirements, and for reporting annually to the Commission on RPS procurement. Finally, on December 4, 2014, the CPUC adopted D.14-12-023 setting RPS compliance and enforcement rules under SB 2 (1X).

### 2.2 Cost Containment

When California’s legislature passed SB 2 (1x), it required the CPUC to develop a limitation on total RPS costs for each electrical corporation. The legislature specified that the cost limitation must prevent the 33% RPS target from causing “disproportionate rate impacts.” If PG&E exceeds the Commission-approved cost cap, it may refrain from entering into new RPS contracts and constructing RPS-eligible facilities unless additional procurement can be undertaken with only “de minimis” rate impacts.

PG&E has made every effort to procure least-cost and best-fit renewable resources. However, recognizing the potential cost impact that RPS procurement can have on customers, PG&E strongly supports the establishment of a clear, stable, and meaningful Procurement Expenditure Limitation (“PEL”) that both informs procurement planning and decisions, and promotes regulatory and market certainty. PG&E urges the Commission to finalize the PEL as soon as possible, given that the RPS statute requires the Commission to report by January 1, 2016 on the status of each IOU in achieving 33% RPS within the adopted PEL, and to propose any necessary modifications to the PEL.

### 2.3 Implementation of Bioenergy Legislation

On September 27, 2012, SB 1122 was passed, requiring California's IOUs to procure 250 megawatts ("MW") in total of new small-scale bioenergy projects 3 MW or less through the Feed-In Tariff ("FIT") Program. The total IOU program MWs are allocated into three technology categories: 110 MW for biogas from wastewater plants and green waste; 90 MW for dairy and other agriculture bioenergy; and 50 MW for forest waste biomass. The allocation of MWs by project type for each IOU, as well as the program design, is being determined by the Commission in proceedings currently underway. PG&E has worked with the Commission and stakeholders in order to ensure that the SB 1122 program is implemented in a way that balances the needs of the bioenergy industry with clear cost containment mechanisms that protect customers from excessive costs. On December 18, 2014, the Commission issued D.14-12-081 to implement SB 1122 and required the IOUs to file a tariff and contract for SB 1122 eligible generation. The IOUs filed their proposed contract and tariff on February 6, 2015.

## 3 Assessment of RPS Portfolio Supplies and Demand

### 3.1 Supply and Demand to Determine the Optimal Mix of RPS Resources

Meeting California's RPS goals in a way that achieves the greatest value for customers continues to be a top priority for PG&E. In particular, PG&E continues to analyze its need to procure cost-effective resources that will enable it to achieve and maintain California's 33% RPS target. PG&E is currently required to procure the following quantities of RPS-eligible products:

- 2011-2013 (First Compliance Period): 20% of the combined bundled retail sales.
- 2014-2016 (Second Compliance Period): A percentage of the combined bundled retail sales that is consistent with the following formula: (.217 * 2014 retail sales) + (.233 * 2015 retail sales) + (.25 * 2016 retail sales).
- 2017-2020 (Third Compliance Period): A percentage of the combined bundled retail sales that is consistent with the following formula: (.27 * 2017 retail sales) + (.29 * 2018 retail sales) + (.31 * 2019 retail sales) + (.33 * 2020 retail sales).
- 2021 and beyond: 33% of combined retail sales in 2021 and each year thereafter.

Based on preliminary results presented in Appendix C.2a, PG&E delivered 27.0% of its power from RPS-eligible renewable sources in 2014.

As described more fully in Section 7 and reported in the current RNS calculations in Appendix C.2a, based on forecasts and expectations of the ability of contracted resources to deliver, PG&E is well-positioned to meet its RPS compliance requirements for the second (2014-2016) and third (2017-2020) compliance periods. Under the current 33% RPS target, PG&E projects that it will not have incremental procurement need until at least 2022, with need beginning in [redacted], after applying Bank beginning in [redacted].

Under a 40% RPS scenario, PG&E modeled the same trajectory through 2020 as described above, but modeled the following RPS requirements starting in 2021:

- 33% of combined bundled retail sales in 2021;
- 37% of combined bundled retail sales in 2022;
- 37% of combined bundled retail sales in 2023; and
- 40% of combined bundled retail sales in 2024 and each year thereafter.

For this scenario, based on forecasts and expectations of the ability of contracted resources to deliver, PG&E projects that it is well-positioned to meet its RPS compliance requirements for the second (2014-2016) and third (2017-2020) compliance periods. PG&E projects that it will have incremental procurement need beginning in [redacted], after applying its Bank towards its physical net short beginning in [redacted].[8]

### 3.2 Supply

#### 3.2.1 Existing Portfolio

PG&E's existing RPS portfolio is comprised of a variety of technologies, project sizes, and contract types. The portfolio includes over 8,000 MW of active projects, ranging from utility-owned solar and small hydro generation to long-term RPS contracts for large wind, geothermal, solar, and biomass to small FIT contracts for solar photovoltaic ("PV"), biogas, and biomass generation. This robust and diversified supply provides a solid foundation for meeting current and future compliance needs; however, the portfolio is also subject to uncertainties as discussed below and in more detail in Sections 6 and 7.

As described in further detail in Section 7.1, for the 2015 RPS Plan, PG&E assumes a volumetric success rate for all executed in-development projects in its RPS portfolio of approximately 99% of total contracted volumes. This rate continues its general trend of increasing from 60% in RPS Plans prior to 2012, to 78% in PG&E's 2012 RPS Plan, to 100% in PG&E's 2013 RPS Plan, and 87% in PG&E's 2014 RPS Plan. This success rate is evolving and highly dependent on the nature of PG&E's portfolio, the general conditions in the renewable energy industry, and the timing of the RPS Plan publication date relative to recent project terminations. While PG&E has continued to see a general trend towards higher project success rates, the change in its success rate assumption from 2014 to 2015 (from 87% to 99%) reflects the recent removal of several projects from PG&E's portfolio due to contract terminations and an update to the "Closely Watched" category described in Section 6.

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8 This projection includes future volumes from mandated programs, such as the RAM and FIT Programs.

Consistent with the project trends reported in its 2014 RPS Plan, PG&E has observed continued progress of key projects under development in its portfolio. Tax incentives (e.g., the federal Investment Tax Credit ("ITC") and Production Tax Credit ("PTC")) have continued to increase many projects' cost-effectiveness, contributing to their eventual completion. Progress in the siting and permitting of projects has also supported PG&E's sustained high success rate. As described in more detail in Section 3, PG&E believes the renewable development market has stabilized for the near-term and the renewable project financing sector will continue to evolve well into the future.

Notwithstanding these positive trends, the timely development of renewable energy facilities remains subject to many uncertainties and risks, including regulatory and legal uncertainties, permitting and siting issues, technology viability, adequate fuel supply, and the construction of sufficient transmission capacity. These challenges and risks are described in more detail in Sections 5 and 6.

For purposes of calculating its demand for RPS-eligible products through the modeling described in Section 6, PG&E does not assume that expiring RPS-eligible contracts in its existing portfolio are re-contracted,[9] although these resources are encouraged to bid into PG&E's future competitive solicitations.

### 3.2.2 Impact of Green Tariff Shared Renewables Program

In 2013, SB 43 enacted the GTSR Program that allows PG&E customers to meet up to 100% of their energy usage with generation from eligible renewable energy resources. On January 29, 2015, the Commission adopted D.15-01-051 implementing a GTSR framework, approving the IOUs' applications, and requiring the IOUs to begin procurement for the GTSR Program in advance of customer enrollment.

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**9** Although the physical net short calculations in PG&E's deterministic model do not include any assumptions related to the re-contracting of expiring RPS-eligible contracts, the stochastic model can re-contract volumes to meet procurement need. Such re-contracting amounts are illustrative only and not prescriptive. PG&E's deterministic and stochastic models are described in more detail below in Section 6.

Pursuant to D.15-01-051, PG&E has submitted several advice letters related to implementation of the GTSR program that are currently pending before the Commission. In February, PG&E filed an advice letter containing its plans for advance procurement for the GTSR Program and identifying the eligible census tracts for environmental justice projects in its service territories.[10] In May, together with Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E), PG&E submitted a Joint Procurement Implementation Advice Letter (JPIAL), addressing each utility's plans for ongoing GTSR Program procurement and RPS resource and renewable energy credit (REC) separation and tracking.[11] Concurrently, PG&E filed a Marketing Implementation Advice Letter (MIAL)[12] and a Customer-Side Implementation Advice Letter (CSIAL)[13] with details regarding implementation. In addition, to accommodate GTSR procurement, PG&E filed Advice Letter 4605-E to change its RAM 6 PPAs and Request for Offer ("RFO") instructions, consistent with the minimum goals for 2015 identified in D.15-01-051.[14]

The GTSR program will impact PG&E's RPS position in two ways: (1) PG&E's RPS supply may be affected; and (2) PG&E's retail sales will be reduced corresponding to program participation. The GTSR decision permits the IOUs to supply Green Tariff customers from an interim pool of existing RPS resources until new dedicated Green Tariff projects come online. Generation from these interim facilities would no longer be counted toward PG&E's RPS targets, which will result in PG&E's RPS supply decreasing. However, there is also a possibility that RPS supply might increase in the future if generation from Green Tariff dedicated projects exceeds the demand of Green Tariff customers. PG&E will implement tracking and reporting protocols for tracking

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[10] PG&E Advice Letter 4593-E (supplemented March 25, 2015).

[11] Advice Letter 4637-E.

[12] Advice Letter 4638-E.

[13] Advice Letter 4639-E.

[14] *See* D.15-01-051, Section 4.2.4, pp. 25-28.

RECs transferred to and from the RPS portfolio and Green Tariff programs. Because the GTSR implementation Advice Letters discussed above[15] have not yet been approved, PG&E's RNS calculation submitted with this RPS Plan does not reflect the impact of GTSR on PG&E's RPS position. Due to the relatively small volumes of the GTSR interim pool compared to PG&E's overall RNS position, PG&E believes that its forecasts of meeting the second and third compliance period RPS targets as well as its incremental need year under either a 33% or 40% RPS would remain the same once these small GTSR volumes are incorporated. PG&E will update future RNS calculations to reflect GTSR program impacts after the advice letters implementing the program are approved.

#### 3.2.3 RPS Market Trends and Lessons Learned

As PG&E's renewable portfolio has expanded to meet the RPS goals, PG&E's procurement strategy has evolved. PG&E's strategy continues to focus on the three key goals of: (1) reaching, and sustaining, the 33% RPS target; (2) minimizing customer cost within an acceptable level of risk; and (3) ensuring it maintains an adequate Bank of surplus RPS volumes to manage annual load and generation uncertainty. However, PG&E is continually adapting its strategy to accommodate new emerging trends in the California renewable energy market and regulatory landscape.

The California renewable energy market has developed and evolved significantly over the past few years. The market now offers a variety of technologies at generally lower prices than seen in earlier years of the RPS Program. The share of these technologies in PG&E's portfolio is changing as a result. For some technologies, such as solar PV, prices have dropped significantly due to various factors including technological breakthroughs, government incentives, and improving economies of scale as more projects come online.

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15 Advice Letters 4637-E, 4638-E and 4639-E.

Another trend driven by growth of renewable resources in the California Independent System Operator ("CAISO") system is the downward movement of mid-day market prices. Many renewable energy project types have little to no variable costs and therefore additions tend to move market clearing prices down the dispatch stack. This has led to a change in the energy values associated with RPS offers, with decreasing value of renewable projects that generate during mid-day hours.

The growth of renewable resources has also produced operational challenges, such as overgeneration situations and negative market prices. Provisions that provide PG&E with greater flexibility to economically bid RPS-eligible resources into the CAISO markets are critical to helping address overgeneration and negative pricing situations that are likely to increase in frequency in the future. These provisions have both operational and customer benefits. From an operational perspective, this flexibility allows PG&E to offer its RPS-eligible resources into the CAISO's economic dispatch, which can reduce the potential for overgeneration conditions and facilitate reliable operation of the electrical grid. In addition, economic bidding enables RPS-eligible resource generation to be curtailed during negative pricing intervals when it is economic to do so, which protects customers from higher costs. Economic curtailment is discussed in greater detail in Section 11.

### 3.3 Demand

PG&E's demand for RPS-eligible resources is a function of multiple complex factors including regulatory requirements and portfolio considerations. Compliance rules for the RPS Program were established in D.12-06-038. In addition, the Commission issued D.11-12-052, to define three statutory PCCs of RPS-eligible products that retail sellers may use for RPS compliance, which impacts PG&E's demand for different types of RPS-eligible products. Finally, PG&E's demand is a function of the risk factors discussed in more detail in Section 6; in particular, uncertainty around bundled retail sales can have a major impact on PG&E's demand for RPS resources, as further detailed below.

### 3.3.1 Near-Term Need for RPS Resources

Because PG&E has no incremental procurement need through [redacted] under a 33% RPS requirement and through [redacted] under a 40% RPS scenario, PG&E proposes to not hold an RPS solicitation in 2015. As discussed in the summary of key issues, PG&E has sufficient time in the coming years to respond to changing market, load forecast, or regulatory conditions and will reassess the need for future RFOs in next year's RPS Plan. Although many factors could change PG&E's RPS compliance position, PG&E believes that its existing portfolio of executed RPS-eligible contracts, its owned RPS-eligible generation, and its expected Bank balances will be adequate to ensure compliance with near-term RPS requirements. Additionally, PG&E expects to procure additional volumes of incremental RPS-eligible contracts in 2016 through mandated procurement programs, such as the RAM, ReMAT, and BioMAT Programs.

### 3.3.2 Portfolio Considerations

One of the most important portfolio considerations for PG&E is the forecast of bundled load. PG&E's most recent Load Forecast, which is used in this RPS Plan, is an April 2015 updated version of the Alternate Scenario Forecast used in the 2014 Bundled Procurement Plan ("BPP") submitted in October 2014 in R.13-12-010. PG&E updates the bundled load forecasts annually to reflect any new events and to capture actual load changes. It is important to emphasize that PG&E's Alternative Scenario is a forecast that includes a number of assumptions regarding events which may or may not occur.

PG&E is currently projecting a decrease in retail sales in 2015 and a continued retail sales decrease through 2024, followed by modest growth thereafter. These changes are driven by the increasing impacts of Energy Efficiency ("EE"), customer-sited generation, and Direct Access ("DA") and CCA participation levels, and are offset slightly by an improving economy and growing electrification of the transportation sector. As described in more detail in Section 6.2.1, PG&E uses its stochastic model to simulate a range of potential retail sales forecasts.

In addition to retail sales forecasts, as discussed in Sections 6, 7, and 8, PG&E's long-term demand for new RPS-eligible project deliveries is driven by: (1) PG&E's

current projection of the success rate for its existing RPS portfolio, which PG&E uses to establish a minimum margin of procurement; and (2) the need to account for its risk-adjusted need, including any Voluntary Margin of Procurement ("VMOP") as determined by PG&E's stochastic model. The risk and uncertainties that justify the need for VMOP are further detailed and quantified in Sections 6 and 7.

### 3.4 Anticipated Renewable Energy Technologies and Alignment of Portfolio With Expected Load Curves and Durations

PG&E's procurement evaluation methodology considers both market value and the portfolio fit of RPS-eligible resources in order to determine PG&E's optimal renewables product mix. With the exception of specific Commission-mandated programs such as the RAM, ReMAT, and BioMAT Programs, PG&E does not identify specific renewable energy technologies or product types (e.g., baseload, peaking as-available, or non-peaking as-available) that it is seeking to align, or fit, with specific needs in its portfolio. Instead, PG&E identifies an RPS-eligible energy need in order to fill an aggregate open position identified in its planning horizon and selects project offers that are best positioned to meet PG&E's current portfolio needs. This is evaluated through the use of PG&E's Portfolio Adjusted Value ("PAV") methodology, which ensures that the procured renewable energy products provide the best fit for PG&E's portfolio at the least cost. Starting in the 2014 RPS RFO, PG&E began utilizing the interim integration cost adder to accurately capture the impact of intermittent resources on PG&E's portfolio. When this adder is finalized by the Commission, PG&E's Net Market Value ("NMV") methodology will be updated to use the values and methodologies of the final integration cost adder. PG&E's PAV and NMV methodologies were described in detail in PG&E's 2014 RPS Solicitation Protocol.[16]

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**16** *See* PG&E, 2014 RPS Solicitation Protocol, pp. 24-28 (available at http://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/RPS2014/RPS_Solicitation_Protocol_01052015.pdf).

### 3.5 RPS Portfolio Diversity

PG&E's RPS portfolio contains a diverse set of technologies, including solar PV, solar thermal, wind, small hydro, bioenergy, and geothermal projects in a variety of geographies, both in-state and out-of-state. PG&E's procurement strategy addresses technology and geographic diversity on a quantitative and qualitative basis.

In the NMV valuation process, PG&E models the location-specific marginal energy and capacity values of a resource based on its forecasted generation profile. Thus, if a given technology or geography becomes "saturated" in the market, then those projects will see declining energy and capacity values in their NMV. This aspect of PG&E's valuation methodology should result in PG&E procuring a diverse resource mix if technological or geographic area concentration is strong enough to change the relative value of different resource types or areas. In addition, technology and geographic diversity have the potential to reduce integration challenges. PG&E's use of the integration cost adder in its NMV valuation process may also result in procurement of different technology types.

Diversity is also considered qualitatively when making procurement decisions. Resource diversity may decrease risk to PG&E's RPS portfolio given uncertainty in future hourly and locational market prices as well as technology-specific development risks.

PG&E recognizes that resource diversity is one option to minimize the overgeneration and integration costs associated with technological or geographic concentration. In general, PG&E believes that less restrictive procurement structures provide the best opportunity to maximize value for its customers, allowing proper response to changing market conditions and more competition between resources, while geographic or technology-specific mandates add additional costs to RPS procurement. PG&E's current quantitative and qualitative approach to resource diversity would remain the same under a 40% RPS scenario as the existing approach described above.

### 3.6 Optimizing Cost, Value, and Risk for the Ratepayer

From 2003 to 2012, PG&E's annual RPS-eligible procurement and generation costs from its existing contracts and utility-owned portfolio grew at a relatively modest pace. However, the costs of the RPS program are becoming more apparent on customer bills and will increase as RPS projects come online in significant quantities. Over the period of two years (2013 and 2014), the renewable generation in PG&E's portfolio increased by approximately the same amount that it grew over the entire prior history of the RPS Program (2003-2012). In addition to cost impacts resulting from the direct procurement of renewable resources, customer costs are also impacted by the associated indirect incremental transmission and integration costs.

PG&E is aware of these direct and indirect cost impacts and will attempt to mitigate them whenever possible, particularly when entering into incremental long-term commitments. PG&E's fundamental strategy for mitigating RPS cost impacts is to balance the opposing objectives of: (1) delaying additional RPS-related costs until deliveries are needed to meet a physical compliance requirement; and (2) managing the risk of being caught in a "seller's market," where PG&E faces potentially high market prices in order to meet near-term compliance deadlines. When these objectives are combined with the general need to manage overall RPS portfolio volatility based on demand and generation uncertainty, PG&E believes it is prudent and necessary to maintain an adequate Bank through the most cost-effective means available.

In addition, PG&E seeks to minimize the overall cost impact of renewables over time through promoting competitive processes that can encourage price discipline, and using the Bank to help limit long-term over-procurement. PG&E generally supports the use of competitive procurement mechanisms that are open to all RPS-eligible technologies and project sizes. As described in greater detail in Section 13.3, as PG&E makes progress toward achieving the 33% RPS target, it expects that the cost impacts of mandated procurement programs that focus on particular technologies or project size may increase the overall costs of PG&E's RPS portfolio for customers as procurement from these programs comprise a larger share of PG&E's incremental procurement goals. This further underscores the need to implement an RPS cost containment mechanism that provides a cap on costs. PG&E supports a technology-neutral procurement process, in which all technologies can compete to offer the best value to customers at the lowest cost.

### 3.7 Long-Term RPS Optimization Strategy

PG&E's long-term optimization strategy seeks to both achieve and maintain RPS compliance through and beyond 2020 and to minimize customer cost within an acceptable level of risk. PG&E's optimization strategy continues to evolve as its RPS compliance position through 2020 and beyond continues to improve. Although PG&E remains mindful of meeting near-term compliance targets, it also seeks to refine strategies for maintaining compliance in a least-cost manner in the long-term (post-2020). PG&E's optimization strategy includes an assessment of compliance risks and approaches to protect against such risks by maintaining a Bank that is both prudent and needed to manage a 33% RPS operating portfolio after 2020. PG&E employs two models in order to optimize cost, value, and risk for the ratepayer while achieving sustained RPS compliance. This optimization analysis results in PG&E's "stochastically-optimized net short" ("SONS"), which PG&E uses to guide its procurement strategy, as further described in Sections 6 and 7.

PG&E's long-term optimization strategy includes three primary components: (1) incremental procurement; (2) possible sales of surplus procurement; and (3) effective use of the Bank. Although PG&E proposes not to hold a 2015 RPS solicitation, future incremental procurement to avoid the need to procure extremely large volumes in any single year remains a central component of PG&E's long-term RPS optimization strategy. In addition to procurement, PG&E's optimization strategy includes consideration of sales of surplus procurement that provide a value to customers.

The third component of the optimization strategy is effective use of the Bank. Under the existing 33% RPS target and current market assumptions, PG&E plans to apply a portion of its projected Bank to meet compliance requirements beginning in [redacted]. Additionally, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in PG&E's stochastic model, while maintaining a minimum Bank size of at least [redacted].

Under a 40% RPS by 2024 scenario, the components of PG&E's optimization strategy would remain the same. However, under the 40% RPS scenario and current market assumptions, PG&E would plan to maintain a minimum Bank size of at least [redacted]. See Section 7 for additional information regarding the use and size of PG&E's Bank.

## 4 Project Development Status Update

In Appendix B, PG&E provides an update on the development of RPS-eligible resources currently under contract but not yet delivering energy. The table in Appendix B updates key project development status indicators provided by counterparties and is current as of June 17, 2015.[17] These key project development status indicators help PG&E to determine if a project will meet its contractual milestones and identify impacts on PG&E's renewable procurement position and procurement decisions.

Within PG&E's active portfolio,[18] there are 107 RPS-eligible projects that were executed after 2002. Seventy-six of these contracts have achieved full commercial operation and started the delivery term under their PPAs. Thirty-one contracts have not

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17 Appendix B includes PPAs procured through the RAM and PV Programs, but does not include small renewable FIT PPAs. PG&E currently has 72 executed Assembly Bill ("AB") 1969 PPAs in its portfolio and 29 ReMAT PPAs, totaling 104 MW of capacity. These small renewable FIT projects are in various stages of development, with 60 already delivering to PG&E under an AB 1969 PPA and 11 delivering to PG&E under a ReMAT PPA. Information on these programs is available at http://www.pge.com/feedintariffs/.

18 PG&E's active portfolio includes RPS-eligible projects that were executed (but not terminated or expired) and CPUC-approved as of June 17, 2015, not including amended post-2002 QF contracts, contracts for the sale of bundled renewable energy and green attributes by PG&E to third parties, Utility-Owned Generation ("UOG") projects, or FIT projects.

started the delivery term under their PPAs. Of the 31 contracts that have not started the delivery term under their PPAs with PG&E: 18 have not yet started construction; five have started construction but are not yet online; and eight are delivering energy, but have not yet started the delivery term under their PPAs. Based on historic experience, projects that have commenced construction are generally more viable than projects in the pre-construction phase, although PG&E expects most of the pre-construction projects currently in its portfolio to achieve commercial operation under their PPA.

## 5 Potential Compliance Delays

Through the considerable experience it has gained over the past decade of RPS procurement, PG&E is familiar with the obstacles confronting renewable energy developers. These include securing financing, siting and permitting projects, expanding transmission capacity, and interconnecting projects to the grid. At both the federal and state levels, new programs and measures continue to be implemented to address these issues. However, even with these efforts, challenges remain that could ultimately impact PG&E's ability to meet California's RPS goals. Moreover, operational issues, such as curtailment, may impact PG&E's RPS compliance. This section describes the most significant RPS compliance risks and some of the steps PG&E is taking to mitigate them.[19]

### 5.1 Project Financing

The financing environment for solar PV and wind projects continues to be healthy, with access to low-cost capital and a variety of ownership structures for project developers. However, for renewable technologies that are less proven, less viable, or

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[19] This section is not intended to provide a detailed justification for an enforcement waiver or a reduction in the portfolio content requirements pursuant to Sections 399.15(b)(5) or 399.16(e). To the extent that PG&E finds that it must seek such a waiver or portfolio balance reduction in the future, it reserves the right to set forth a more complete statement, based upon the facts as they appear in the future, in the form of a petition or as an affirmative defense to any action by the Commission to enforce the RPS compliance requirements.

reflect a higher risk profile, the financing environment is more constrained, with higher costs of capital and fewer participants willing to lend or invest.

Federal and state incentives such as the PTC and ITC continue to fuel renewable growth in California. In 2015, the Internal Revenue Service extended the applicable dates for the "beginning of construction" guidance for PTC-eligible facilities to January 1, 2015, and the "placed in service" date to January 1, 2017.[20] This allows the PTC or ITC tax benefits for non-solar facilities to continue well beyond 2014. Solar energy facilities continue to be eligible for a 30% ITC if they are placed in service by December 31, 2016.[21] The five-year and seven-year Modified Accelerated Cost Recovery System ("MACRS") allows for accelerated tax depreciation deductions to renewable tangible property.[22] These tax incentives and the MACRS depreciation deductions enable businesses to reduce their tax liability and accelerate the rate of return on renewable investments. They also provide a workable framework for projects to negotiate financing. As a result, tax incentives have spurred significant investment in renewable energy and generally amount to between 35 and 60 cents per dollar ("¢/$") of capital cost.

Tax equity remains a core financing tool for renewable developments, and ownership structures such as Master Limited Partnerships and Yield Cos are also being utilized as project sponsors market and investors competitively shop for solar and wind investments. These structures allow developers who cannot use tax benefits efficiently

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20 Notice 2015-25 allows a taxpayer to claim a PTC under Section 45 of the Internal Revenue Code ("IRC"), or a 30% ITC under Section 48 (ITC) in lieu of the PTC, for eligible facilities such as wind, geothermal, biomass, marine, landfill gas, and hydro, if the facility began construction before January 1, 2015 or was placed in service by January 1, 2017.

21 Section 48 of the IRC allows for a tax credit equal to 30% of project's qualifying costs for certain types of commercial energy projects, including solar, geothermal, fuel cells, and small wind projects, and a 10% tax credit for geothermal, micro turbines and combined heat and power. The tax credit is realized in the year that the project is placed in service.

22 MACRS provides for a five-year tax cost recovery period for renewable solar, wind, geothermal, fuel cells and combined heat and power tangible property. Certain biomass property is eligible for a seven-year tax cost recovery period under MACRS.

to barter the benefits to large corporations or investors in exchange for cash infusions for their projects. At this time, tax incentive structures after 2016 are unknown. The PTC and 30% ITC incentives end in 2016. Unless the tax code is modified or extended, the renewable energy ITC will drop to 10% after December 31, 2016. However, there are efforts underway to extend or modify the PTC and ITC.[23] Despite the uncertainty surrounding renewable energy project tax incentives, PG&E believes there are indications that healthy trends for renewable project financing will continue.

### 5.2 Siting and Permitting

PG&E works with various stakeholder groups toward finding solutions for environmental siting and permitting issues faced by renewable energy development. For example, PG&E works collaboratively with environmental groups, renewable energy developers and other stakeholders to encourage sound policies through a Renewable Energy Working Group, an informal and diverse group working to protect ecosystems, landscapes and species, while supporting the timely development of energy resources in the California desert and other suitable locations. Long-term and comprehensive planning and permitting processes can help better inform and facilitate renewable development.

PG&E is hopeful that these and other efforts will establish clear requirements that developers and other interested parties can satisfy in advance of the submission of offers to PG&E's future solicitations, and will, as a result, help decrease the time it takes parties to site and permit projects while ensuring environmental integrity.

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23 H.R. 2412 would extend the renewable energy ITC for a period of five years for eligible renewable solar, small wind energy, fuel cell, micro turbine, thermal energy and combined heat and power system properties that begin construction before January 1, 2022.

In addition, in its proposed budget for fiscal year 2016, the Obama administration proposes to modify and permanently extend the renewable PTC and ITC. For facilities that begin construction in 2016 or later, the proposal would make the PTC permanent and refundable. Solar facilities that qualify for the ITC would be eligible to claim the PTC. The proposal would also permanently extend the ITC at the 30 percent credit level, which is currently scheduled to expire for properties placed in service after December 31, 2016, and it would make permanent the election to claim the ITC in lieu of the PTC for qualified facilities eligible for the PTC.

Permitting challenges for projects are improving as a result of these and other efforts to streamline and adjust the permitting process for renewable energy projects. While these improvement efforts are ongoing, permitting and siting hurdles remain for renewables projects. Common issues may include challenges related to farmland designation and Williamson Act contracts, tribal and cultural resources areas, protected species, and county-imposed moratoriums. These hurdles may impact development schedules for projects.

### 5.3 Transmission and Interconnection

Achieving timely interconnection is an important part of the project development process. Delays in achieving interconnection can occur for various reasons, including the delay of substation construction, permitting issues, telecommunications delays, or overly aggressive timeline assumptions. While delays in interconnection can lead to delays in project development, such delays to date have not had a major impact on PG&E's ability to meet its RPS procurement targets.

Over the past few years, the CAISO and the IOUs have seen significant increases in the number of requests for grid interconnection. As the number of proposed RPS-eligible projects continues to increase in California, planning for how these projects would be connecting into the California grid has become increasingly challenging. The growth in these requests has, in turn, extended estimated project development timelines, which creates a significant barrier to financing projects endeavoring to come online within tight contractual milestone dates. Similarly, the growth in interconnection requests has made it difficult to estimate reliable interconnection study results and to identify necessary transmission build-outs.

Accordingly, PG&E has initiated a number of internal efforts and collaborated on external initiatives to address these challenges at both the transmission and distribution levels. Recent notable changes in the distribution-level interconnection process included: (1) amending the Wholesale Distribution Tariff in October 2014 to address modifications similar to those made to the CAISO's Tariff; and (2) amending Rule 21 in January 2015 to capture the technological advances offered by smart inverters.

Additionally, over the past few years, PG&E has worked with the CAISO and industry stakeholders in ongoing stakeholder initiatives enhancing the transmission-level interconnection processes. Most significant among the changes has been the Generator Interconnection and Deliverability Allocation Procedures, which has streamlined the process for identifying customer-funded transmission additions and upgrades under a single comprehensive process. This initiative also provides incentives for renewable energy developers to interconnect to the CAISO grid at the most cost-effective locations. PG&E has also actively contributed to the CAISO's Interconnection Process Enhancements stakeholder initiative that seeks to continuously review potential enhancements to the generator interconnection procedures.

Finally, at the intersection of transmission-level and distribution-level interconnections, is the Distributed Generation Deliverability ("DGD") process. In 2013, PG&E collaborated extensively with the CAISO to implement the first annual cycle, and the second and third cycles were successfully completed in 2014 and 2015, respectively. Under the DGD Program, the CAISO conducts an annual study to identify MW amounts of available deliverability at transmission nodes on the CAISO-controlled grid. Based on the deliverability assessment results, distributed generation facilities that are located or seeking interconnection at nodes with identified available deliverability may apply to the appropriate Participating Transmission Owner ("PTO") to receive an assignment of deliverability for Resource Adequacy ("RA") counting purposes.

### 5.4 Curtailment of RPS Generating Resources

As discussed in more detail in Section 11, if RPS curtailed volumes increase substantially due to CAISO market or reliability conditions, curtailment may present an RPS compliance challenge. In order to better address this challenge, PG&E's stochastic model incorporates estimated levels of curtailment, which enables PG&E to plan for appropriate levels of RPS procurement to meet RPS compliance even when volumes are curtailed. Additional detail on these assumptions is provided in Section 6.2.

### 5.5 Risk-Adjusted Analysis

PG&E employs both a deterministic and stochastic approach to quantifying its remaining need for incremental renewable volumes. As described further in Section 6, deliveries from projects experiencing considerable development challenges associated with project financing, permitting, transmission and interconnection, among others, are excluded from PG&E's net short calculation.

PG&E's experience with prior solicitations is that developers often experience difficulties managing some of the development issues described above. As described in Section 8, PG&E's current expected RPS need calculation incorporates a minimum margin of procurement to account for some anticipated project failure and delays in PG&E's existing portfolio, which are captured in PG&E's deterministic model. These deterministic results are time-sensitive and do not account for all of the risks and uncertainties that can cause substantial swings in PG&E's portfolio.

While it has made reasonable efforts to minimize risks of project delays or failures in an effort to comply with the 33% RPS Program procurement targets, PG&E cannot predict with certainty the circumstances—or the magnitude of the circumstances—that may arise in the future affecting the renewables market or individual project performance.

## 6 Risk Assessment

Dynamic risks, such as the factors discussed in Section 5 that could lead to potential compliance delays, directly affect PG&E's ability to plan for and meet compliance with the RPS requirements. To account for these and additional uncertainties in future procurement, PG&E models the demand-side risk of retail sales variability and the supply-side risks of generation variability, project failure, curtailment, and project delays in quantitative analyses.

Specifically, PG&E uses two approaches to modeling risk: (1) a deterministic model; and (2) a stochastic model. The deterministic model tracks the expected values of PG&E's RPS target and deliveries to calculate a "physical net short," which represents a point-estimate forecast of PG&E's RPS position and constitutes a reasonable minimum margin of procurement, as required by the RPS statute. These deterministic results serve as the primary inputs into the stochastic model. The stochastic model[24] accounts for additional compounded and interactive effects of various uncertain variables on PG&E's portfolio to suggest a procurement strategy at least cost within a designated level of non-compliance risk. The stochastic model provides target procurement volumes for each compliance period, which result in a designated Bank size for each compliance period. The Bank is then primarily utilized as Voluntary Margin of Procurement or VMOP to mitigate dynamic risks and uncertainties and ensure compliance with the RPS.

This section describes in more detail PG&E's two approaches to risk mitigation and the specific risks modeled in each approach. Section 6.1 identifies the three risks accounted for in PG&E's deterministic model. Section 6.2 outlines the four additional risks accounted for in PG&E's stochastic model. Section 6.3 describes how the risks described in the first two sections are incorporated into both models, including details about how each model operates and the additional boundaries each sets on the risks. Section 6.4 notes how the two models help guide PG&E's optimization strategy and

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24 The stochastic model specifically employs both Monte Carlo simulation of risks and genetic algorithm optimization of procurement amounts. A Monte Carlo simulation is a computational algorithm commonly used to account for uncertainty in quantitative analysis and decision making. A Monte Carlo simulation provides a range of possible outcomes, the probabilities that they will occur and the distributions of possible outcome values. A genetic algorithm is a problem-solving process that mimics natural selection. That is, a range of inputs to an optimization problem are tried, one-by-one, in a way that moves the problem's solution in the desired direction—higher or lower—while meeting all constraints. Over successive iterations, the model "evolves" toward an optimal solution within the given constraints. In the case of PG&E's stochastic model, a genetic algorithm is employed to conduct a first-order optimization to ensure compliance at the identified risk threshold while minimizing cost.

procurement need. Section 7 discusses the results for both the deterministic and stochastic models and introduces the physical and optimized net short calculations presented in Appendices C.2a and C.2b. Section 8 addresses PG&E's approach to the statutory minimum and voluntary margins of procurement.

### 6.1 Risks Accounted for in Deterministic Model

PG&E's deterministic approach models three key risks:

1) **Standard Generation Variability:** the assumed level of deliveries for categories of online RPS projects.

2) **Project Failure:** the determination of whether or not the contractual deliveries associated with a project in development should be excluded entirely from the forecast because of the project's relatively high risk of failure or delay.

3) **Project Delay:** the monitoring and adjustment of project start dates based on information provided by the counterparty (as long as deliveries commence within the allowed delay provisions in the contract).

The table below shows the methodology used to calculate each of these risks, and to which category of projects in PG&E's portfolio the risks apply. More detailed descriptions of each risk are described in the subsections below.

**TABLE 6-1**
**PACIFIC GAS AND ELECTRIC COMPANY**
**DETERMINISTIC MODEL RISKS**

| RISK | METHODOLOGY | APPLIES TO |
|---|---|---|
| **Standard Generation Variability** | • For non-QF projects executed post-2002, 100% of contracted volumes<br>• For non-hydro QFs, typically based on an average of the three most recent calendar year deliveries<br>• Hydro QFs, UOG and IDWA generation projections are updated to reflect the most recent hydro forecast. | Online Projects |
| **Project Failure** | • In Development projects with high likelihood of failure are labeled “OFF” (0% deliveries assumption)<br>• All other In Development projects are “ON” (assume 100% of contracted delivery) | In Development Projects |
| **Project Delay** | • Professional judgment / Communication with counterparties | Under Construction Projects / Under Development Projects / Approved Mandated Programs |

### 6.1.1 Standard Generation Variability

With respect to its operating projects, PG&E’s forecast is divided into three categories: non-Qualifying Facilities (“QF”); non-hydro QFs; and hydro projects. The forecast for non-QF projects is based on contracted volumes. The forecast for non-hydro QFs is based on the average of the three most recent calendar year deliveries. The forecast for hydro QFs is typically based on historical production, calendar year deliveries, and regularly updated with PG&E’s latest internal hydro updates. The UOG and Irrigation District and Water Agency (“IDWA”) forecast is based on PG&E’s latest internal hydro updates. Future years’ hydro forecasts assume average water year production. These assumptions are included in this RPS Plan as Appendix G.

### 6.1.2 Project Failure

To account for the development risks associated with securing project siting, permitting, transmission, interconnection, and project financing, PG&E uses the data collected through PG&E’s project monitoring activities in combination with best professional judgment to determine a given project’s failure risk profile. PG&E categorizes its portfolio of contracts for renewable projects into two risk categories: OFF (represented with 0% deliveries) and ON (represented with 100% deliveries). This approach reflects the reality of how a project reaches full development; either all of the generation from the project comes online, or none of the generation comes online.

1. **OFF/Closely Watched** – PG&E excludes deliveries from the “Closely Watched” projects in its portfolio when forecasting expected incremental need for renewable volumes. “Closely Watched” represents deliveries from projects experiencing considerable development challenges as well as once-operational projects that have ceased delivering and are unlikely to restart. In reviewing project development monitoring reports, and applying their best professional judgment, PG&E managers may consider the following factors when deciding whether to categorize a project as “Closely Watched”:

    - Actual failure to meet significant contractual milestones (e.g., guaranteed construction start date, guaranteed commercial operation date, etc.).
    - Anticipated failure to meet significant contractual milestones due to the project’s financing, permitting, and/or interconnection progress or to other challenges (as informed by project developers, permitting agencies, status of CAISO transmission studies or upgrades, expected interconnection timelines, and/or other sources of project development status data).
    - Significant regulatory contract approval delays (e.g., 12 months or more after filing) with no clear indication of eventual authorization.
    - Developer’s statement that an amendment to the PPA is necessary in order to preserve the project’s commercial viability.
    - Whether a PPA amendment has been executed but has not yet received regulatory approval.
    - Knowledge that a plant has ceased operation or plant owner/operator’s statement that a project is expected to cease operations.

Final forecasting assessments are project-specific and PG&E does not consider the criteria described above to be exclusive, exhaustive, or the sole criteria used to categorize a project as "Closely Watched."[25]

2. **ON** – Projects in all other categories are assumed to deliver 100% of contracted generation over their respective terms. There are three main categories of these projects. The first category, which denotes projects that have achieved commercial operation or have officially begun construction, represents the majority of "ON" projects. Based on empirical experience and industry benchmarking, PG&E estimates that this population is highly likely to deliver. The second category of "ON" projects is comprised of those that are in development and are progressing with pre-construction development activities without foreseeable and significant delays. The third category of "ON" projects represents executed and future contracts from CPUC-mandated programs. While there may be some risk to specific projects being successful, because these volumes are mandated, the expectation is that PG&E will replace failed volumes with replacement projects within a reasonable timeline.

#### 6.1.3 Project Delay

Because significant project delays can impact the RNS, PG&E regularly monitors and updates the development status of RPS-eligible projects from PPA execution until commercial operation. Through periodic reporting, site visits, communication with counterparties, and other monitoring activities, PG&E tracks the progress of projects towards completion of major project milestones and develops estimates for the construction start (if applicable) and commercial operation of projects.

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**25** For instance, PG&E may elect to count deliveries from projects that meet one or more of the criteria if it determines, based on its professional judgment, that the magnitude of challenges faced by the projects do not warrant exclusion from the deterministic forecast. Similarly, the evaluation criteria employed by PG&E could evolve as the nature of challenges faced by the renewable energy industry, or specific sectors of it, change.

### 6.2 Risks Accounted for in Stochastic Model

The risk factors outlined in the deterministic model are inherently dynamic conditions that do not fully capture all of the risks affecting PG&E’s RPS position. Therefore, PG&E has developed a stochastic model to better account for the compounded and interactive effects of various uncertain variables on PG&E’s portfolio. PG&E’s stochastic model assesses the impact of both demand- and-supply-side variables on PG&E’s RPS position from the following four categories:

1) **Retail Sales Variability:** This demand-side variable is one of the largest drivers of PG&E’s RPS position.
2) **Project Failure Variability:** Considers additional project failure potential beyond the “on-off” approach in the deterministic model.
3) **Curtailment:** Considers buyer-ordered (economic), CAISO-ordered or PTO-ordered curtailment.
4) **RPS Generation Variability:** Considers additional RPS generation variability above and beyond the small percentages in the deterministic model.

When considering the impacts that these variables can have on its RPS position, PG&E organizes the impacts into two categories: (1) persistent across years; and (2) short-term (e.g., effects limited to an individual year and not highly correlated from year-to-year). Table 6-2 below lists the impacts by category, while showing the size of each variable’s overall impact on PG&E’s RPS position.

**TABLE 6-2**
**PACIFIC GAS AND ELECTRIC COMPANY**
**CATEGORIZATION OF IMPACTS ON RPS POSITION**

Higher Impact on RPS Position

Lower Impact on RPS Position

| Impact | Categorization |
|---|---|
| **1. Retail Sales Variability**:<br>Changes in retail sales tend to persist beyond the current year (e.g., economic growth, EE, CCA and DA, and distributed generation impacts). | **Variable and persistent**<br>(*If an outcome occurs, the effect persists through more than one year).* |
| **2. RPS Generation Variability:**<br>Variability in yearly generation is largely an annual phenomenon that has little persistence across time. | **Variable and short-term**<br>(*If an outcome occurs, the effect may only occur for the individual year.)* |
| **3. Curtailment:**<br>Impact increases with higher penetration of renewables and will be persistent. | **Variable and persistent** |
| **4. Project Failure Variability:**<br>Lost volume from project failure persists through more than one year. | **Variable and persistent** |

### 6.2.1 Retail Sales Variability

PG&E's retail sales are impacted by factors such as weather, economic growth or recession, technological change, EE, levels of DA and CCA participation, and distributed generation. PG&E generates a distribution of the bundled retail sales for each year using a model that simulates thousands of possible bundled load scenarios. Each scenario is based on regression models for load in each end use sector as a function of weather and economic conditions with consideration of future policy impacts on EE, electric vehicles, and distributed generation. However, the variability in load loss due to DA and CCA is not modeled in this same way. As load loss due to DA is currently capped by California statute and cannot be expanded without additional legislation, PG&E is not forecasting substantial increases in DA. Load loss due to CCA departure is modeled as an expected value based on an increased forecast of CCA departure. Because forecast errors tend to carry forward into future years, the cumulative impact of load forecast variability grows with time. Appendix F.1 lists the resulting simulated retail sales and summary statistics for the period 2015-2030.

Appendices F.5a and F.5b show the resulting simulated RPS target when accounting for the retail sales variability for the period 2015-2030 in the 33% and 40% RPS, respectively.

### 6.2.2 RPS Generation Variability

Based on analysis of historical hydro generation data from [redacted], wind generation data from [redacted], and generation data from solar and other technologies where available, PG&E estimated a historical annual variability measured by the coefficient of variation of each resource type. [redacted] Due to significant variability in annual precipitation, small hydro demonstrates the largest annual variability (coefficient of variation of [redacted]). The remaining resource types range in annual variability from [redacted] for biomass and geothermal, [redacted] for solar PV and solar thermal to [redacted] for wind. Collectively, technology diversity helps to reduce the overall variation, because variability around the mean is essentially uncorrelated among technologies. Appendices F.3a and F.3b list the resulting simulated generation and summary statistics for the period 2015-2030 in the 33% and 40% RPS, respectively.

To better understand the wide range of variability of the above risks and thus, the need for a stochastic model to optimize PG&E's procurement volumes, Appendices F.4a and F.4b, combine the Project Failure and RPS Generation Variability factors into a "total deliveries" probability distribution, shows how these variables interact in the 33% and 40% RPS, respectively.

### 6.2.3 Curtailment

The stochastic model also estimates the potential for RPS curtailment. Curtailment can result from either buyer-ordered (economic), CAISO-ordered or PTO-ordered curtailment (the latter two driven by system stability issues, not economics). [redacted]

[redacted][26] These modeling assumptions will not necessarily align with the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance. Please see Section 11 for more information regarding curtailment.

#### 6.2.4 Project Failure Variability

To model the project failure variability inherent in project development, PG&E assumes that project viability for a yet-to-be-built project is a function of the number of years until its contract start date. That is, a new project scheduled to commence deliveries to PG&E next year is considered more likely to be successful than a project scheduled to begin deliveries at a much later date. The underlying assumption is that both PG&E and the counterparty know more about a project's likelihood of success the closer the project is to its initial delivery date, and the counterparty may seek to amend or terminate a non-viable project before it breaches the PPA. Working from this assumption, PG&E assigns a probability of project success for new, yet-to-be-built projects equal to [redacted]. For example, a project scheduled to come online in five years or more is assumed to have a [redacted] chance of success. This success rate is based on experience and is reflective of higher project development success rates of PG&E's RPS portfolio in more recent years.

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**26** [redacted]

Although PG&E's current existing portfolio of projects may have higher rates of success, the actual success rate for projects in the long-term may be higher or lower. Projects that are re-contracted, in contrast, are modeled at a [redacted] success rate. Appendices F.2a and F.2b list PG&E's simulated failure rate and summary statistics for the period 2015-2030 in the 33% and 40% RPS, respectively.

#### 6.2.5 Comparison of Model Assumptions

Table 6-3 below shows a comparison of how PG&E's deterministic and stochastic models each handle uncertainty with regard to retail sales, project failure, RPS generation, and curtailment. Section 7 provides a more detailed summary of the results from PG&E's deterministic and stochastic modeling approaches.

**TABLE 6-3**
**COMPARISON OF UNCERTAINTY ASSUMPTIONS**
**BETWEEN PG&E'S DETERMINISTIC AND STOCHASTIC MODELS**

| Uncertainty | Deterministic Model | Stochastic Model |
|---|---|---|
| 1) Retail Sales Variability | Uses most recent PG&E bundled retail sales forecast for next 5 years and 2014 LTPP for later years | Distribution based on most recent (2015) PG&E bundled retail sales forecast. |
| 2) Project Failure Variability | Only turns "off" projects with high likelihood of failure per criteria. "On" projects assumed to deliver at Contract Quantity. | Uses [redacted] to model a success rate for all "on" yet-to-be-built projects in the deterministic model. Thus, for a project scheduled to come online in 5 years, the project success rate is [redacted]. This success rate is based on PG&E's experience that the further ahead in the future a project is scheduled to come online, the lower the likelihood of project success. Re-contracted projects are assumed to have a [redacted] success rate. |
| 3) RPS Generation Variability | Non-QF projects executed post-2002, 100% of contracted volumes<br><br>For non-hydro QFs, typically based on an average of the three most recent calendar year deliveries<br><br>Hydro QFs, UOG and IDWA generation projections are updated to reflect the most recent hydro forecast. | Hydro: [redacted] annual variation<br>Wind: [redacted] annual variation<br>Solar: [redacted] annual variation<br>Biomass and Geothermal: [redacted] annual variation |
| 4) Curtailment[27] | None | 33% RPS Target: [redacted] of RPS requirement<br>40% RPS Scenario: [redacted] of RPS requirement through 2021, increasing to [redacted] in 2024 and beyond. |

### 6.3 How Deterministic Approach Is Modeled

The deterministic model is a snapshot in time of PG&E's current and forecasted RPS position and procurement need. The deterministic model relies on currently available generation data for executed online and in development RPS projects as well

27 These modeling assumptions will not necessarily align with the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance.

as PG&E's most recent bundled retail sales forecast. The results from the deterministic model determine PG&E's "physical net short," which represents the best current point-estimate forecast of PG&E's RPS position today. The deterministic model should not be seen as a static target because the inputs are updated as new information is received.

### 6.4 How Stochastic Approach Is Modeled

The stochastic model adds rigor to the risk-adjustment embedded in the deterministic model—using Monte Carlo simulation—and optimizes its results to achieve the lowest cost possible given a specified risk of non-compliance and the stochastic model's constraints.

The methodology for the stochastic model is as follows:

1) Create an optimization problem by establishing the (a) objectives, (b) inputs, and (c) constraints of the model.

   a. The objective is to minimize procurement cost.

   b. The inputs are a range of potential incremental RPS-eligible deliveries (new and re-contracted volumes[28]) in each year of the [redacted] timeframe. The potential incremental procurement is restricted to a range of no less than zero and no more than [redacted] GWh, which is in addition to volumes available for re-contracting.[29]

   c. The constraints are: (1) to keep PG&E's risk of non-compliance to less than [redacted]; and (2) to restrict PG&E's Bank over time to the size necessary to meet compliance objectives within the specified risk threshold.

2) The stochastic model then solves the optimization problem by examining thousands of combinations of procurement need in each year. For each of these

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28 Although the physical net short calculations do not include any assumptions related to the re-contracting of expiring RPS-eligible contracts, the stochastic model can also re-contract volumes to meet procurement need. Such re-contracting amounts are illustrative only and not prescriptive.

29 PG&E limited modeling to a maximum addition of [redacted] GWh per year in order to avoid modeling outcomes that required "lumpy" procurement patterns. Large swings in annual procurement targets could lead to boom/bust development cycles and could expose PG&E's customers to additional price volatility risk.

combinations, the model runs hundreds of iterations as part of its Monte Carlo simulation of uncertainty for each of the risk factors in the stochastic model to test if the constraints are met. If the solution for that combination of inputs fits within the given constraints, it is a valid outcome.

3) For each valid outcome, the mean Net Present Value ("NPV") cost of meeting that procurement need is calculated based on PG&E's RPS forward price curve.

4) Finally, the model sorts the NPV of the potential procurement outcomes from smallest to largest, thus showing the optimal RPS-eligible deliveries needed in the years [redacted] to ensure compliance based on the modeled assumptions.

The modeled solution becomes a critical input into PG&E's overall RPS optimization strategy, but the outputs are subject to further analysis based upon best professional judgment to determine whether factors outside the model could lead to better outcomes. For example, the model does not currently consider speculating on price volatility through sales of PG&E's Bank in the near-term and additional incremental procurement in the long-term. Nor does the model consider the opposite strategy of advance procurement of RPS-eligible products in 2015 for purposes of reselling those products in the future at a profit. As a general matter, PG&E does not approach RPS procurement and compliance as a speculative enterprise and so has not modeled or otherwise proposed such strategies in this Plan. However, PG&E will consider selling surplus non-bankable RPS volumes in its portfolio and, in doing so, may seek to sell surplus bankable volumes if it can still maintain an adequate Bank and if market conditions are favorable.

### 6.5 Incorporation of the Above Risks in the Two Models Informs Procurement Need and Sales Opportunities

Incorporating inputs from the deterministic model, the stochastic model provides results that lead to a forecasted procurement need or SONS, expected Bank usage and thus an anticipated Bank size, for each compliance period. The SONS for the 33% and 40% RPS are shown in Row La of PG&E's Alternate RNS in Appendices C.2a and C.2b.

The stochastic model does not provide guidance on potential sales of excess banked procurement at this time. However, as PG&E encounters economic opportunities to sell volumes, PG&E will use the stochastic model to help evaluate whether the proposed sale will increase the cumulative non-compliance risk for [redacted] above the [redacted] threshold.

The results of both the deterministic and stochastic models are discussed further in Section 7 and minimum margin of procurement is addressed in Section 8.

## 7 Quantitative Information

As discussed in Section 6, PG&E's objectives for this RPS Plan are to both achieve and maintain RPS compliance and to minimize customer cost within an acceptable level of risk. To do that, PG&E uses both deterministic and stochastic models. This section provides details on the results of both models and references RNS tables provided in Appendix C. Appendices C.1a and C.1b presents the RNS in the form required by the *Administrative Law Judge's Ruling on Renewable Net Short* issued May 21, 2014 in R.11-05-005 ("ALJ RNS Ruling") and includes results from PG&E's deterministic model only, while Appendices C.2a and C.2b are a modified version of Appendices C.1a and C.1b to present results from both PG&E's deterministic and stochastic models. These modifications to the table are necessary in order for PG&E to adequately show its results from its stochastic optimization.

### 7.1 Deterministic Model Results

Results from the deterministic model under the 33% RPS target are shown as the physical net short in Row Ga of Appendices C.1a and C.2a, while the results from the deterministic model under the 40% RPS scenario are shown as the physical net short in Row Ga of Appendices C.1b and C.2b. Appendices C.1a and C.1b provide a physical net short calculation using PG&E's Bundled Retail Sales Forecast for years 2015-2019 and the LTPP sales forecast for 2020-2035, while Appendices C.2a and C.2b rely exclusively on PG&E's internal Bundled Retail Sales Forecast. Following the methodology described in Section 6.1, PG&E currently estimates a long-term volumetric success rate of approximately 99% for its portfolio of executed-but-not-operational projects. The annual forecast failure rate used to determine the long-term volumetric success rate is shown in Row Fbb of Appendices C.2a and C.2b. This success rate is a snapshot in time and is also impacted by current conditions in the renewable energy industry, discussed in more detail in Section 5, as well as project-specific conditions. In addition to the current long-term volumetric success rate, Rows Ga and Gb of Appendices C.2a and C.2b depict PG&E's expected compliance position using the current expected need scenario before application of the Bank.

#### 7.1.1 33% RPS Target Results

Under the current 33% RPS target, PG&E is well-positioned to meet its second (2014-2016) and third (2017-2020) compliance period RPS requirements. As shown in Row Gb of Appendix C.1b, the deterministic model shows a forecasted second compliance period RPS Position of 30.3% and a third compliance period RPS position of [redacted]. Row Ga of Appendix C.2a also shows a physical net short of approximately 500 GWh beginning in 2022.

#### 7.1.2 40% RPS Scenario Results

Under a 40% RPS scenario, PG&E is forecasted to meet its second (2014-2016) and third (2017-2020) compliance period RPS requirements. As shown in Row Gb of Appendix C.2b, PG&E has a forecasted second compliance period RPS Position of 30.3% and a third compliance period RPS position of [redacted]. Row Ga of Appendix C.2b shows a physical net short of approximately 3,000 GWh beginning in 2022.

### 7.2 Stochastic Model Results

This subsection describes the results from the stochastic model and the SONS calculation for both the current 33% RPS target and a 40% RPS scenario. All assumptions and caveats stated in the discussion of the 33% RPS target results apply to the 40% RPS scenario results, unless otherwise stated. However, note that the

40% RPS scenario results apply to this particular RPS scenario only, and PG&E's optimization strategy may differ under other scenarios that have a different RPS target or timeline. Because PG&E uses its stochastic model to inform its RPS procurement, PG&E has created an Alternate RNS in Appendix C.2a for the current 33% RPS target and Appendix C.2b for the 40% RPS scenario. Appendices C.1a and C.1b provide an incomplete representation of PG&E's optimized net short, as the formulas embedded in the RNS form required by the ALJ RNS Ruling do not enable PG&E to capture its stochastic modeling inputs and outputs. In Appendices C.2a and C.2b, two additional rows have been added. Rows Gd and Ge show the stochastically-adjusted net short ("SANS"), which incorporates the risks and uncertainties addressed in the stochastic model. This is prior to any applications of the Bank, but includes additional procurement needed for maintaining an optimized Bank size. Additionally, PG&E has modified the calculations in Rows La and Lb in order to more accurately represent PG&E's SONS.

#### 7.2.1 Stochastically-Optimized Net Short to Meet Non-Compliance Risk Target – 33% RPS Target

To evaluate possible procurement strategies, PG&E selected a cumulative ([redacted]) non-compliance risk target of [redacted], which PG&E views as the maximum reasonable level of non-compliance risk. Figure 7-1 shows the model's forecasted procurement need and resulting Bank usage under the current 33% RPS. Under this projection, a portion of the Bank is used to meet PG&E's compliance need beginning in [redacted], the first year showing a stochastically-adjusted net short, and continuing throughout the decade, while reserving a portion of the Bank to be maintained as VMOP to manage risks discussed in Section 6. Appendix C.2a provides the detailed results. Annual forecasted Bank usage is shown in Row Ia of this Appendix. After accounting for Bank usage, the first year of incremental procurement need is forecasted as [redacted]. This compliance period need represents PG&E's SONS, which is detailed in Row La. The SONS for [redacted] is approximately [redacted] GWh, which increases to approximately [redacted] GWh by 2030. The [redacted] SONS is [redacted] than the physical net short in Row Ga for [redacted], as the SONS [redacted].

[redacted]

[redacted]

Because the stochastic model inputs change over time, these estimates should be seen as a snapshot in time rather than a static target and the procurement targets will be re-assessed as part of future RPS Plans.

#### 7.2.2 Bank Size Forecasts and Results – 33% RPS Target

Figure 7-2 shows PG&E's current and forecasted cumulative Bank from the first compliance period through 2030. PG&E's total Bank size as of the end of compliance period is approximately 900 GWh, shown as existing Bank in Figure 7-2. The stochastic model's results currently project PG&E's Bank size to [redacted] GWh by [redacted] (as shown in Figure 7-2, as well as in Appendix C.2a, Row J). [redacted]

[redacted]

[redacted]

[redacted]

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[redacted]

There is a trade-off between non-compliance risk and Bank size. A larger Bank size decreases non-compliance risk. However, a larger Bank size may also increase procurement costs. Higher risk scenarios would result in a lower Bank size and, as discussed above, would increase PG&E's probability of being in a position in which PG&E might need to make unplanned purchases to comply with its RPS requirement. In that situation, PG&E might not be able to avoid higher procurement costs due to the potential for upward pressure on prices caused by the need for unplanned purchases.

### 7.2.3 Minimum Bank Size – 33% RPS Target

PG&E performed a simulation of variability in PG&E's future generation and RPS compliance targets over [redacted] years—i.e., the amount of the RPS generation ("delivery") net of RPS compliance targets ("target")—and found that a Bank size of at least [redacted] is the minimum Bank necessary to maintain a cumulative non-compliance risk of no greater than [redacted]. The difference between delivery and target can be thought of as the potential "need" (if negative) or "surplus" (if positive) that PG&E has in any one year.

Figure 7-3 shows this distribution based on the deterministic procurement necessary to meet the expected RPS targets with expected generation during [redacted]. This time period was selected as it best represents a "steady state" period when the Bank approaches a minimum level and moderate incremental procurement is required to maintain compliance. Note that given the uncertainty around the inputs in the stochastic model, without a Bank to accommodate such uncertainty, the amount of RPS generation is almost as likely to miss the RPS target as exceed it. One standard deviation over [redacted] is approximately [redacted] GWh, as indicated on Figure 7-3. That is, given this particular procurement scenario, about 68% of the simulations have a difference that is up to plus or minus approximately [redacted] GWh.

However, this does not suggest that a Bank of [redacted] GWh would be adequate to cover potential shortfalls over this [redacted]-year period. It would result in an unacceptable non-compliance risk over [redacted] of approximately [redacted]. Thus, PG&E must maintain a Bank size higher than this amount to limit the risk of non-compliance to an acceptable level. Based on current model assumptions and inputs, Figure 7-3 shows that approximately [redacted] of the time, PG&E would have a greater than [redacted] GWh deficit in meeting compliance for [redacted].

[redacted]

[redacted]

As stated in Section 7.2.2, the stochastic model's results show PG&E's forecasted [redacted] PG&E's strategy is to procure steady, incremental volumes in order to avoid the need to procure extremely large volumes in any single year to meet compliance needs and maintain minimum Bank levels. [redacted]

Because the model inputs change over time, estimates of the Bank size resulting from the implementation of the procurement plan will also change. In practice, the actual outcome will more likely be a mix of factors both detracting from and contributing to meeting the target, which is what the probability distribution in Figure 7-3 illustrates.

### 7.2.4 Stochastically-Optimized Net Short to Meet Non-Compliance Risk Target – 40% RPS Scenario

Figure 7-4 shows the model's forecasted procurement need and recommended Bank usage in the 40% RPS scenario. Under this projection, a portion of the Bank is used to meet PG&E's compliance need beginning in [redacted], while reserving a portion of the Bank to be maintained as VMOP to manage risks discussed in Section 6. Appendix C.2b provides the detailed results. Annual forecasted Bank usage can be seen in Row Ia of this Appendix. The first year of procurement need is currently forecasted as [redacted]. This compliance period need represents PG&E's SONS, which is detailed in Row La. The SONS for [redacted] is approximately [redacted] GWh, which increases to approximately [redacted] GWh by [redacted]. The [redacted] SONS is [redacted] than the physical net short shown in Row Ga for [redacted].

[redacted]

[redacted]

[redacted]

[redacted]

### 7.2.5 Bank Size Forecasts and Results – 40% RPS Scenario

Figure 7-5 shows PG&E's current and forecasted cumulative Bank from Compliance Period 1 through 2030 under a 40% RPS scenario. PG&E's total Bank size as of the end of Compliance Period 1 is approximately 900, shown as existing Bank in Figure 7-5. The stochastic model's results currently project PG&E's [redacted] (as shown in Figure 7-5, as well as in Appendix C.2b, Row J).

[redacted]

[redacted]

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[redacted]

### 7.2.6 Minimum Bank Size – 40% RPS Scenario

Using a similar approach as described in Section 7.2.3, under a 40% by 2024 scenario, a minimum Bank size of at least [redacted] GWh is necessary to maintain a cumulative non-compliance risk of no greater than [redacted]. The minimum Bank size in this scenario is greater than the Bank required for the 33% RPS target, as more volumes are required to meet the higher RPS, but also [redacted].

[redacted]

[redacted]

The stochastic model's procurement strategy results show PG&E's forecasted [redacted]. Based on current model assumptions and inputs, Figure 5-6 shows that approximately [redacted] of the time, PG&E would have a greater than [redacted] GWh deficit in meeting compliance for [redacted].

### 7.3 Implications for Future Procurement

PG&E plans to continually refine both its deterministic and stochastic models, thus the procurement strategy outlined above is applicable to this RPS Plan only. In future years, PG&E's procurement strategy will likely change, based on updates to the data and algorithms in both models. Additionally, PG&E will continue to assess the value to its customers of sales of surplus procurement. Consistent with the Commission's adopted RNS methodology, PG&E's physical net short and cost projections do not include any projected sales of bankable contracted deliveries. However, PG&E will consider selling non-bankable surplus volumes in its portfolio and, in doing so, may identify and propose in the future opportunities to secure value for its customers through the sale of bankable surplus procurement. PG&E will update its physical RNS if it executes any such sale agreements and will include in its optimized RNS and SONS specific future plans to sell RPS procurement.

## 8 Margin of Procurement

When analyzing its margin of procurement, PG&E considers two key components: (1) a statutory minimum margin of procurement to address some anticipated project failure or delay, for both existing projects and projects under contract but not yet online, that is accounted for in PG&E's deterministic model; and (2) a VMOP, which aims to mitigate the additional risks and uncertainties that are accounted for in PG&E's stochastic model. Specifically, PG&E's VMOP intends to (a) mitigate risks associated with short-term variability in load; (b) protect against project failure or delay exceeding forecasts; and (c) manage variability from RPS resource generation. In so doing, PG&E's VMOP helps to eliminate the need at this time to procure long-term contracts above the 33% RPS target by creating a buffer that enables PG&E to manage the year-to-year variability that result from risks (a)-(c). This section discusses both of these components and how each is incorporated into PG&E's quantitative analysis of its RPS need.

### 8.1 Statutory Minimum Margin of Procurement

The RPS statute requires the Commission to adopt an "appropriate minimum margin of procurement above the minimum procurement level necessary to comply with the [RPS] to mitigate the risk that renewable projects planned or under contract are delayed or canceled."[30] PG&E's reasonableness in incorporating this statutory minimum margin of procurement into its RPS procurement strategy is one of the factors the Commission must consider if PG&E were to seek a waiver of RPS enforcement because conditions beyond PG&E's control prevented compliance.[31]

As described in more detail in Section 6, PG&E has developed its risk-adjusted RPS forecasts using a deterministic model that: (1) excludes volumes from contracts at risk of failure from PG&E's forecast of future deliveries; and (2) adjusts expected commencement of deliveries from contracts whose volumes are included in the model (so long as deliveries commence within the allowed delay provisions in the contract). PG&E considers this deterministic result to be its current statutory margin of procurement.[32] However, as discussed in Sections 6 and 7, these results are variable and subject to change, and thus PG&E does not consider this statutory margin of procurement to sufficiently account for all of the risks and uncertainties that can cause substantial variation in PG&E's portfolio. To better account for these risks and uncertainties, PG&E uses its stochastic model to assess a VMOP, as described further below.

### 8.2 Voluntary Margin of Procurement

The RPS statute provides that in order to meet its compliance goals, an IOU may voluntarily propose a margin of procurement above the statutory minimum margin

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30 Cal. Pub. Util. Code § 399.13(a)(4)(D).

31 *Id.*, § 399.15(b)(5)(B)(iii).

32 In the past PG&E has seen higher failure rates from its overall portfolio of executed-but-not-operational RPS contracts. However, as the renewables market has evolved—and projects are proposed to PG&E at more advanced stages of development—PG&E has observed a decrease in the expected failure rate of its overall portfolio. The more recent projects added to PG&E's portfolio appear to be significantly more viable than some of the early projects in the RPS Program, resulting in lower current projections of project failure than have been discussed in past policy forums. However, its revised success rate assumption (from 87% to 99%) also reflects several recent contract terminations from PG&E's portfolio due to and an update to the "Closely Watched" category described in Section 6.

of procurement.[33] As discussed further in Sections 6 and 7, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in the stochastic model.

While PG&E's current optimization strategy projects [redacted]. When used as VMOP, the Bank will help to avoid long-term over-procurement above the 33% RPS target, and will thus reduce long-term costs of the RPS Program. Since the model inputs change over time, estimates of the Bank and VMOP are not a static target and will change, so these estimates should be seen as a snapshot in time. Additional discussion on the need for and use of the Bank and VMOP are included in Sections 6 and 7.

Additionally, as a portion of the Bank will be used as VMOP, PG&E will continue to reflect zero volumes in Row D of its RNS tables, consistent with how it has displayed the VMOP in past RNS tables.

## 9 Bid Selection Protocol

As described in Sections 3 and 7, PG&E is well positioned to meet its RPS targets, under both a 33% RPS target and a 40% RPS scenario, until at least [redacted]. As a result, PG&E proposes that it not issue a 2015 RPS solicitation. PG&E will continue to procure RPS-eligible resources in 2016 through other Commission-mandated programs, such as the ReMAT and RAM Programs.

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33 *Id.*,§ 399.13(a)(4)(D).

### 9.1 Proposed TOD Factors

PG&E sets its TOD factors based on expected hourly prices. Given the high penetration of solar generation expected through 2020 and beyond, PG&E forecasts that there will be significant periods of time during the mid-day when net loads are low, resulting in prices that will be low or negative, especially in the spring. This expectation is consistent with forecasts of net load that have been publicized by the CAISO.[34] In addition, given the low mid-day loads, PG&E sees its peak demand (and resulting higher market prices) moving to later in the day. Capacity value has also become significantly less important in the selection process because: (1) market prices for generic capacity are low; and (2) net qualifying capacity using effective load carrying capability is also low. Thus, PG&E would simplify its PPAs and include only a single set of TOD factors to be applied to both energy-only and fully deliverable resources.

PG&E is proposing to update its TOD factors and TOD periods as follows:

<u>Recommendation (New TODs)</u>

- Move peak period from HE16-HE21 to HE17-HE22
- Move mid-day period from HE07-HE15 to HE10-HE16
- Move night period from HE22-HE06 to HE23-HE09
- Move March back to the “Spring” period
- Result: Summer=Jul.-Sep., Winter=Oct.-Feb., Spring=Mar.-Jun.; and Peak=HE17-HE22, Mid-day=HE10-HE16, Night=HE23-HE09

**TABLE 9-1**
**[PROPOSED RPS TIME OF DELIVERY FACTORS]**

| | Peak | Mid-Day | Night |
|---|---|---|---|
| Summer | 1.479 | 0.604 | 1.087 |
| Winter | 1.399 | 0.718 | 1.122 |
| Spring | 1.270 | 0.280 | 1.040 |

34 *See*, *e.g.*, *CAISO Transmission Plan 2014-2015*, pp. 162-163 (approved March 27, 2015) (available at http://www.caiso.com/Documents/Board-Approved2014-2015TransmissionPlan.pdf).

## 10 Consideration of Price Adjustment Mechanisms

The ACR requires each IOU to "describe how price adjustments (e.g., index to key components, index to Consumer Price Index, price adjustments based on exceeding transmission or other cost caps, etc.) will be considered and potentially incorporated into contracts for RPS-eligible projects with online dates occurring more than 24 months after the contract execution date."[35]

PG&E will consider a non-standard PPA with pricing terms that are indexed, but indexed pricing should be the exception rather than the rule. Customers could benefit from pricing indexed to the cost of key components, such as solar panels or wind turbines, if those prices decrease in the future. Conversely, customers would also face the risk that they will pay more for the energy should prices of those components increase. Asking customers to accept this pricing risk reduces the rate stability that the legislature has found is a benefit of the RPS Program.[36] In order to maximize the RPS Program's benefits to customers, cost risk should generally be borne by developers.

Additionally, indexing greatly complicates offer selection, negotiation and approval. It may be challenging to incorporate contract price adjustment mechanisms into PPA negotiations when there is no clear, well-established and well-defined agreed-upon index. There are many components to the cost of construction of a renewable project, and indexes tied to these various components may move in different directions. The increased complexity inherent in such negotiations is counter to the Commission's expressed desire to standardize and simplify RPS solicitation processes.[37]

Moreover, Sellers may not have as much incentive to reduce costs if certain cost components are indexed. For example, a price adjustment based on the cost of solar panels (i.e., if panel costs are higher than expected, the price may adjust upward) may

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35 ACR, p. 15.

36 *See* Cal. Pub. Util. Code § 399.11(b)(5).

37 *See* D.11-04-030, pp. 33-34.

not create enough incentive to minimize those costs. This would create a further level of complexity in contract administration and regulatory oversight.

Finally, PG&E does not recommend that PPA prices be linked to the Consumer Price Index ("CPI"). The CPI is completely unrelated to the cost of the renewable resource, and is instead linked to increases in prices of oil and natural gas, food, medical care and housing. Indexing prices to unrelated commodities heightens the derivative and speculative character of these types of transactions.

## 11 Economic Curtailment

In D.14-11-042, the Commission approved curtailment terms and conditions for PG&E's pro forma RPS PPA.[38] In addition, the Commission directed the IOUs to report on observations and issues related to economic curtailment, including reporting to the Procurement Review Group ("PRG").[39] In May 2015, PG&E made a presentation to its PRG on economic curtailment. This section provides information to the Commission and parties regarding PG&E's observations and issues related to economic curtailment both for the market generally, and PG&E's specific scheduling practices for its RPS-eligible resources.

With regard to market conditions generally, the frequency of negative price periods in 2015 has generally increased in the Real-Time Markets, even during the low hydro conditions of 2015. During January through May 2015, negative price intervals in the CAISO Five Minute Market for the North of Path 15 Hub occurred more than 1,800 times (4.2% of 5 minute intervals) compared to 1,100 times (2.5%) during the same period in 2014. Similarly, the ZP26 Hub prices for this period in 2015 were negative over 4,100 times (9.5%), a substantial increase over the 2014 results of 1,400 times (3.3%). Increased negative price periods have led to increased curtailments of renewable resources that are economically bid. The specific

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38 D.14-11-042, pp. 43-44.

39 *Id.*, pp. 42-43.

occurrences of negative price periods and overgeneration events are largely unpredictable; [redacted][40] [redacted] PG&E submits bids for these resources based on the resource's opportunity costs, subject to contractual, regulatory, and operational constraints. This also includes the incremental costs of compliance instruments required to comply with the 33% RPS target. PG&E provided more detail concerning its RPS bidding strategy in its proposed 2014 Bundled Procurement Plan ("BPP") which was filed with the Commission in October 2014 and is currently pending at the Commission.[41]

[redacted]

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40 [redacted]

41 *See* PG&E, *Proposed 2014 Bundled Procurement Plan*, R.13-12-010, Appendix K (Bidding and Scheduling Protocol) (October 3, 2014).

[redacted] 42 [redacted] 43 While direct benefits of economic bidding include avoided costs and CAISO market payments associated with negative prices, there can be other important benefits, including potentially avoiding the cost impacts across the rest of PG&E's portfolio due to extreme negative price periods and also potentially enhancing CAISO system reliability by helping to mitigate the occurrences, duration, or severity of negative price periods or overgeneration events.

With regard to longer-term RPS planning and compliance, in order to ensure that RPS procurement need forecasts account for curtailment, PG&E adds curtailment as a risk adjustment within the stochastic model. Under the 33% RPS target, PG&E assumes curtailment [redacted] 44 under a 40% RPS scenario, PG&E expects curtailment to increase in line with recent CAISO estimates [redacted].45 These modeling assumptions will not necessarily align with the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance. PG&E will continue to observe curtailment events and update its curtailment

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42 [redacted]

43 [redacted]

44 [redacted]

45 [redacted]

assumptions as needed. Implementation of these assumptions in PG&E's modeling is discussed in more detail in Section 6.2.3.

Finally, PG&E continues to review its existing portfolio of RPS contracts to determine if additional economic curtailment flexibility may be available to help address the increase in negative pricing events.

## 12 Expiring Contracts

The ACR requires PG&E to provide information on contracts expected to expire in the next 10 years.[46] Appendix E lists the projects under contract to PG&E that are expected to expire in the next 10 years. The table includes the following data:

1. PG&E Log Number
2. Project Name
3. Facility Name
4. Contract Expiration Year
5. Contract Capacity (MW)
6. Expected Annual Generation (GWh)
7. Contract Type
8. Resource Type
9. City
10. State
11. Footnotes identifying if PG&E has already secured the expiring volumes through a new PPA

As indicated in Appendix G, PG&E's RNS calculations assume no re-contracting. Re-contracting is not precluded by this assumption, but rather it reflects that proposed material amendments (i.e., those needed to avoid project failure) or extensions to existing contracts will be evaluated against current offers.

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46 ACR, p. 16.

## 13 Cost Quantification

This section summarizes results from actual and forecasted RPS generation costs (including incremental rate impacts), shows potential increased costs from mandated programs, and identifies the need for a clear cost containment mechanism to address RPS Program costs. Tables 1 through 4 in Appendix D provide an annual summary of PG&E's actual and forecasted RPS costs and Page 1 of Appendix D outlines the methodology for calculating the costs and generation.

### 13.1 RPS Cost Impacts

Appendix D quantifies the cost of RPS-eligible procurement—both historical (2003-2014) and forecast (2015-2030). From 2003 to 2014, PG&E's annual RPS-eligible procurement and generation costs have continued to increase. Compared to an annual cost of $523 million in 2003, PG&E incurred more than [redacted] in procurement costs for RPS-eligible resources in 2014.

RPS Program costs impact customers' bills. Incremental rate impacts, defined as the annual total cost from RPS-eligible procurement and generation divided by bundled retail sales, effectively serve as an estimate of a system average bundled rate for RPS-eligible procurement and generation. While this formula does not provide an estimate of the renewable "above-market premium" that customers pay relative to a non-RPS-eligible power alternative, the annual rate impact results in Tables 1 and 2 of Appendix D illustrate the potential rate of growth in RPS costs and the impact this growth will have on average rates, all other factors being equal. Annual rate impact of the RPS Program increased from 0.7¢/kWh in 2003 to an estimated 3.5¢/kWh in 2016, meaning the average rate impact from RPS-eligible procurement has increased more than five-fold in approximately 12 years. This growth rate is projected to continue increasing through 2020, as the average rate impact is forecasted to increase to 3.9¢/kWh. In addition to the increasing RPS costs and incremental rate impacts on customer costs resulting from the direct procurement of the renewable resources, there are incremental indirect transmission and integration costs associated with that procurement.

### 13.2 Procurement Expenditure Limit

Section 399.15(f) provides that the Commission waive the RPS obligations of an electrical corporation once it meets the cost containment limitation, provided that additional resources cannot be procured without exceeding "a de minimis increase in rates." The methodology for the PEL, the Commission's cost containment mechanism, is still under development. As discussed in Section 2.2, PG&E looks forward to the Commission finalizing the PEL methodology and implementing it, to ensure that customers are adequately protected and promote regulatory certainty and support procurement planning.

### 13.3 Cost Impacts Due to Mandated Programs

As PG&E makes progress toward achieving the RPS goal of 33%, the cost impacts of mandated procurement programs that focus on particular technologies or project size increase over time, and procurement from those programs increasingly comprises a larger share of PG&E's incremental procurement goals. In general, mandated procurement programs do not optimize RPS costs for customers because they restrict flexibility and optionality to achieve emissions reductions by mandating procurement through a less efficient and more costly manner. For instance, research shows that market-based mechanisms, like cap-and-trade, that allow multiple and flexible emissions reduction options, have lower costs than mandatory mechanisms like technology targets that allow only a subset of those options.[47] Studies have also

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**47** *See*, *e.g.*, Palmer and Burtraw, "Cost-Effectiveness of Renewable Electricity Policies" (2005) (available at http://www.rff.org/Documents/RFF-DP-05-01.pdf); Sergey Paltsev et. al, "The Cost of Climate Policy in the U.S." (2009) (available at http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.177.6721&rep=rep1&type=pdf); Palmer, Sweeney, and Allaire, "Modeling Policies to Promote Renewable and Low-Carbon Sources of Electricity" (2010) (available at http://www.rff.org/RFF/Documents/RFF-BCK-Palmeretal%20-LowCarbonElectricity-REV.pdf).

shown that renewable electricity mandates increase prices and costs,[48] and procurement mandates within California's RPS decrease efficiency in the same way.

Mandates restrict the choices to meet the RPS targets, removing potentially less expensive options from the market. This can increase prices in two ways: first, by disqualifying those less expensive participants and second, by creating a less robust market for participants to compete.[49] PG&E's customers also pay incremental costs due to the administrative costs associated with managing separate solicitations for mandated resources. In addition, smaller project sizes for mandated programs create a greater number of projects which, in turn, affect interconnection and transmission availability and costs. Finally, mandated programs do not enable PG&E to procure the technology, size, vintage, location and other attributes that would best fit its portfolio. As a result, PG&E's costs for managing its total generation and portfolio increase. For these reasons, PG&E supports a technology neutral procurement process, in which all technologies can compete to demonstrate which projects provide the best value to customers at the lowest cost.

**14 Imperial Valley**

For the IOUs' 2014 RPS solicitations, the Commission did not specifically require any remedial measures to bolster procurement from Imperial Valley projects but required continued monitoring of IOUs' renewable procurement activities in the Imperial Valley area.[50] Even without remedial measures in PG&E's 2014 RPS Solicitation, the Independent Evaluator monitoring that solicitation found that:

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**48** *See*, *e.g.*, Institute for Energy Research, "Energy Regulation in the States: A Wake-up Call" (available at http://www.instituteforenergyresearch.org/pdf/statereport.pdf); Manhattan Institute, "The High Cost of Renewable Electricity Mandates" (available at http://www.manhattan-institute.org/html/eper_10.htm).

**49** *See*, Fischer and Preonas, "Combining Policies for Renewable Energy: Is the Whole Less Than the Sum of Its Parts?" (2010) (available at http://www.rff.org/Documents/Fischer_Preonas_IRERE_2010.pdf).

**50** D.14-11-042, pp. 15-16.

> Overall, the response of developers to propose Imperial Valley projects was robust and PG&E's selection of Imperial Valley Offers was representative of that response. Arroyo perceives no evidence that PG&E failed in any way to perform outreach to developers active in the Imperial Valley or that there was any structural impediment in the RFO process that hindered the selection of competitively priced Offers for projects in the Imperial Valley.[51]

Given the robustness of the response from Imperial Valley projects in the 2014 RPS solicitation, as well as the 2013 RPS solicitation, and given the fact that PG&E is not planning on conducting a 2015 RPS solicitation, there does not appear to be a need to adopt any special remedial measures for the Imperial Valley as a part of the RPS Plan.

The ACR also directs the IOUs to report on any CPUC-approved RPS PPA for projects in the Imperial Valley that are under development, and any RPS projects in the Imperial Valley that have recently achieved commercial operation.[52] PG&E has one PPA under contract in the Imperial Valley. That project is in development. Commercial operation is expected in 2016, with deliveries under the PPA beginning in 2020.

## 15 Important Changes to Plans Noted

This section describes the most significant changes between PG&E's 2014 RPS Plan and its 2015 RPS Plan. A complete redline of the draft 2015 RPS Plan against PG&E's 2014 RPS Plan is included as Appendix A. This section identifies and summarizes the key changes and differences between the 2014 RPS Plan and the proposed 2015 RPS Plan. Specifically, the table below provides a list of key differences between the two RPS Plans:

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51 PG&E, *Advice Letter 4632-E*, p. 40, Section 2 (IE Report) (May 7, 2015).

52 ACR, p. 19.

| Reference | Area of Change | Summary of Change | Justification |
|---|---|---|---|
| Section 1 | Section format and structure | Remove "Executive Summary" from Introduction. | Ease of document flow. |
| Entire RPS Plan | Consideration of a Higher RPS Requirement | Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario. | ACR at pp.5-6. |
| Section 2.1 | Commission Implementation of SB 2 (1x) | Include discussion of D.14-12-023, setting RPS compliance and enforcement rules under SB 2 (1X). | ACR at p. 4. |
| Section 3.2.2 | Impact of Green Tariff Shared Renewable Program | Include discussion of impact of Green Tariff Shared Renewable Program on RPS position. | D.14-11-042; D.15-01-051. |
| Section 3.4 | Anticipated Renewable Energy Technologies and Alignment of Portfolio With Expected Load Curves and Durations | Include discussion of integration cost adder as part of LCBF bid evaluation methodology. | ACR at p.15. |
| Section 3.5 | RPS Portfolio Diversity | Include discussion of efforts to increase portfolio diversity. | ACR at p.10. |
| Section 5.4 | Curtailment of RPS Generating Resources | Include discussion of economic curtailment as a potential compliance delay. | ACR at p.16. |

| Reference | Area of Change | Summary of Change | Justification |
|---|---|---|---|
| Section 11 | Economic Curtailment | Include discussion of economic curtailment. | ACR at p.16. |
| Appendix C.1b | Renewable Net Short Calculations – 40% RPS Scenario | Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario. | ACR at pp.5-6. |
| Appendix C.2b | Alternate Renewable Net Short Calculations – 40% RPS Scenario | Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario. | ACR at pp.5-6. |
| Appendix F.2b | Project Failure Variability – 40% RPS Scenario | Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario. | ACR at pp.5-6. |
| Appendix F.3b | RPS Generation Variability – 40% RPS Scenario | Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario. | ACR at pp.5-6. |
| Appendix F.4b | RPS Deliveries Variability – 40% RPS Scenario | Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario. | ACR at pp.5-6. |
| Appendix F.5b | RPS Target Variability – 40% RPS Scenario | Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario. | ACR at pp.5-6. |

## 16 Safety Considerations

PG&E is committed to providing safe utility (electric and gas) service to its customers. As part of this commitment, PG&E reviews its operations, including energy procurement, to identify and mitigate, to the extent possible, potential safety risks to the public and PG&E's workforce and its contractors. Because PG&E's role in ensuring the safe construction and operation of RPS-eligible generation facilities depends upon whether PG&E is the owner of the generation or is simply the contractual purchaser of RPS-eligible products (e.g., energy and RECs), this section is divided into separate discussions addressing each of these situations.

### 16.1 Development and Operation of PG&E-Owned, RPS-Eligible Generation

While PG&E is not proposing as part of its 2015 RPS Plan to develop additional utility-owned renewable facilities, its existing RPS portfolio contains a number of such facilities. To the extent that PG&E builds, operates, maintains, and decommissions its own RPS-eligible generation facilities, PG&E follows its internal standard protocols and practices to ensure public, workplace, and contractor safety. For example, PG&E's Employee Code of Conduct describes the safety of the public, employees and contractors as PG&E's highest priority.[53] PG&E's commitment to a safety-first culture is reinforced with its Safety Principles, PG&E's Safety Commitment, Personal Safety Commitment and Keys to Life.[54] These tools were developed in collaboration with PG&E employees, leaders, and union leadership and are intended to provide clarity and support as employees strive to take personal ownership of safety at PG&E. Additionally, PG&E seeks all applicable regulatory approvals from governmental

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53 *See* PG&E, "Employee Code of Conduct" (August 2013) (available at http://www.pgecorp.com/aboutus/corp_gov/coce/employee_conduct_standards.shtml). *See*, *e.g.*, PG&E, "Contractor, Consultant, and Supplier Code of Conduct," p. 3 (available at http://www.pgecorp.com/aboutus/ethics_compliance/con_con_ven/).

54 *See* PG&E, "Employee Code of Conduct" *supra* (describing the Safety Principles, Safety Commitment, Personal Safety Commitment and Keys to Life).

authorities with jurisdiction to enforce laws related to worker health and safety, impacts to the environment, and public health and welfare.

As more fully detailed in PG&E's testimony in its General Rate Case ("GRC"),[55] the top priority of PG&E's Electric Supply organization is public and employee safety, and its goal is to safely operate and maintain its generation facilities. In general, PG&E ensures safety in the development and operation of its RPS-eligible facilities in the same manner as it does for its other UOG facilities. This includes the use of recognized best practices in the industry.

PG&E operates each of its generation facilities in compliance with all local, state and federal permit and operating requirements such as state and federal Occupational Safety and Health Administration ("OSHA") and the California Public Utilities Commission's General Order 167. PG&E does this by using internal controls to help manage the operations and maintenance of its generation facilities, including: (1) guidance documents; (2) operations reviews; (3) an incident reporting process; (4) a corrective action program; (5) an outage planning and scheduling process; (6) a project management process; and (7) a design change process.

PG&E's Environmental Services organization also provides direct support to the generation facilities, with a focus on regulatory compliance. Environmental consultants are assigned to each of the generating facilities and support the facility staff.

With regard to employee safety, Power Generation employees develop a safety action plan each year. This action plan focuses on various items such as clearance processes and electrical safety, switching and grounding observations, training and qualifications, expanding the use of Job Safety Analysis tools, peer-to-peer recognition, near-hit reporting, industrial ergonomics, and human performance.

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**55** *See* PG&E, *Prepared Testimony, 2014 GRC, Application 12-11-009*, Exhibit (PG&E-6), Energy Supply, pp. 1-11, 2-17, 2-44, 2-66, 4-13 (available at http://www.pge.com/regulation/).

Employees also participate in an employee led Driver Awareness Team established for the sole purpose of improving driving. An annual motor vehicle incident ("MVI") Action Plan is developed and implemented each year. This action plan focuses on vehicle safety culture and implements the Companywide motor vehicle safety initiatives in addition to specific tools such as peer driving reviews and 1 800 phone number analysis to reduce MVIs.

The day-to-day safety work in the operation of PG&E's generation facilities consists of base activities such as:

- Industrial and office ergonomics training/evaluations
- Illness and injury prevention
- Health and wellness training
- Regulatory mandated training
- Training and re certification for the safety staff
- Culture based safety process
- Asbestos and lead awareness training
- Safety at Heights Program
- Safe driving training
- First responder training
- Preparation of safety tailboards and department safety procedures
- Proper use of personal protective equipment
- Incident investigations and communicating lessons learned
- Employee injury case management
- Safety performance recognition
- Public safety awareness

The safety focus of PG&E's hydropower operations includes the safety of the public at, around, and/or downstream of PG&E's facilities; the safety of our personnel at and/or traveling to PG&E's hydro facilities; and the protection of personal property potentially affected by PG&E's actions or operations. With regard to public safety, PG&E is developing and implementing a comprehensive public safety program that includes: (1) public education, outreach and partnership with key agencies; (2) improved warning and hazard signage at hydro facilities; (3) enhanced emergency response preparedness, training, drills and coordination with emergency response organizations; and (4) safer access to hydro facilities and lands, including trail access, physical barriers, and canal escape routes.

PG&E has also funded specific hydro-related projects that correct potential public and employee safety hazards, such as Arc Flash Hazards, inadequate ground grids, and waterway, penstock, and other facility safety condition improvements.

PG&E will never be satisfied in its safety performance until there is never an injury to any of its employees, contractors, or members of the public. Over the past several years, PG&E's Power Generation organization has been creating a culture of safety first with strong leadership expectations and an increasingly engaged workforce. Fundamental to a strong safety culture is a leadership team that believes every job can be performed safely and seeks to eliminate barriers to safe operations. Equally important is the establishment of an empowered grass roots safety team that can act to encourage safe work practices among peers. Power Generation's grass roots team is led by bargaining unit employees from across the organization who work to include safety best practices in all the work they do. These employees are closest to the day-to-day work of providing safe, reliable, and affordable energy for PG&E's customers and are best positioned to implement change that can improve safety performance.

### 16.2 Development and Operation of Third-Party–Owned, RPS-Eligible Generation

The vast majority of PG&E's procurement of products to meet RPS requirements has been from third-party generation developers. In these cases, local, state and federal agencies that have review and approval authority over the generation facilities are charged with enforcing safety, environmental and other regulations for the Project, including decommissioning. While this authority has not changed, PG&E intends to add additional contract provisions to its contract forms to reinforce the developer's obligations to operate in accordance with all applicable safety laws, rules and regulations as well as Prudent Electrical Practices, which are the continuously evolving industry standards for operations of similar electric generation facilities. Additionally, the new provisions will seek to implement lessons learned and instill a continuous improvement safety culture that mirrors PG&E's approach to safety.

Specifically, the safety language that PG&E is developing builds upon the former standard of Good Utility Practices to a new standard of Prudent Utility Practices, which includes greater detail on the types of activities covered by this standard, including but not limited to safeguards, equipment, personnel training, and control systems.

Safety is also addressed as part of a generator's interconnection process, which requires testing for safety and reliability of the interconnected generation. PG&E's general practice is to declare that a facility under contract has commenced deliveries under the PPA only after the interconnecting utility and the CAISO have concluded such testing and given permission to commence commercial operations.

PG&E receives monthly progress reports from generators who are developing new RPS-eligible resources where the output will be sold to PG&E. As part of this progress report, generators are required to provide the status of construction activities, including OSHA recordables and work stoppage information. Additionally, the new contract provisions would require reporting of Serious Incidents and Exigent Circumstances shortly after they occur. If the generator has repeated safety violations or challenges, the generator could be at greater risk of failing to meet a key project development milestone or failing to meet a material obligation set forth in the PPA.

The decommissioning of a third-party generation project is not addressed in the form contract. In many cases, it may be expected that a third-party generator may continue to operate its generation facility after the PPA has expired or terminated, perhaps with another off-taker. Any requirements and conditions for decommissioning of a generation facility owned by a third-party should be governed by the applicable permitting authorities.

## 17 Energy Storage

AB 2514, signed into law in September 2010, added Section 2837, which requires that the IOUs' RPS procurement plans incorporate any energy storage targets and policies that are adopted by the Commission as a result of its implementation of AB 2514. On October 17, 2013, the CPUC issued D.13-10-040 adopting an energy storage procurement framework and program design, requiring that PG&E execute 580 MW of storage capacity by 2020, with projects required to be installed and operational by no later than the end of 2024. In accordance with the guidelines in the decision, PG&E submitted an application to procure energy storage resources on February 28, 2014. In D.14-10-045, the CPUC approved PG&E's application with modifications. PG&E will file final storage RFO results for CPUC approval by December 1, 2015. In addition, PG&E is participating in a new proceeding, R.15-03-011, which the Commission opened in March 2015 to consider policy and implementation refinements to the energy storage procurement framework and program design.

PG&E considers eligible energy storage systems to help meet its Energy Storage Program targets through its RPS procurement process, Energy Storage RFO, as well as other CPUC programs and channels such as the Self Generation Incentive Program (SGIP). PG&E's LCBF methodology considers the additional value offered by RPS-eligible generation facilities that incorporate energy storage. Further detail on PG&E's energy storage procurement can be found in its biennial Energy Storage Plan.[56]

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**56** *See* PG&E, *Application of Pacific Gas and Electric Company (U 39-E) for Authorization to Procure Energy Storage Resources (2014-2015 Biennial Cycle)*, (available at: http://www.cpuc.ca.gov/NR/rdonlyres/D9CACD21-AB1C-411A-8B79-84FB28E88C58/0/PGE_StorageApplication.pdf).

# APPENDIX A

Redline Showing Changes in August 4, 2015 Draft 2015 RPS Plan Compared to December 23, 2014 Final (Revision 1) RPS Plan

August 4, 2015

**Public**

**PACIFIC GAS AND ELECTRIC COMPANY**

**RENEWABLES PORTFOLIO STANDARD**

**~~2014~~2015 RENEWABLE ENERGY PROCUREMENT PLAN (~~FINAL~~DRAFT VERSION)**

**AUGUST 4, 2015**

# Public

PUBLIC~~DECEMBER 23, 2014~~

~~REVISION 1~~

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Appendix A: Redline Showing Changes in ~~the~~August 4, 2015 Draft 2015 RPS Plan Compared to December 23, 2014 Final (Revision 1) ~~2014 RPS Plan (including Appendices B, D, E, F, G, and J) Compared to December 8, 2014 Final~~ RPS Plan ~~(including Appendices B, D, E, F, G, and J)~~

Appendix B: Project Development Status Update

Appendix C~~.1~~: Quantitative Information~~:~~

Appendix C.1a: Renewable Net Short Calculations ~~Based on CPUC Required Formatting and Assumptions (Using May 2014 Vintage PG&E Bundled Retail Sales Forecast in Near Term (2014-2018) and LTPP Methodology (2019-2033))~~ – 33% RPS Target

Appendix C.~~2: Quantitative Information:~~ 1b: Renewable Net Short Calculations ~~Based on PG&E Assumptions (Using May 2014 Vintage PG&E Bundled Retail Sales Forecast) and with Additional Data to Reflect Portfolio Optimization Strategy~~ – 40% RPS Scenario

~~Appendix D: Cost Quantification~~

Appendix C.2a: Alternate Renewable Net Short Calculations – 33% RPS Target

Appendix C.2b: Alternate Renewable Net Short Calculations – 40% RPS Scenario

Appendix D: Procurement Information Related to Cost Quantification

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Appendix F~~.1-F.5~~: Stochastic Modeling Results

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Appendix F.2b: Project Failure Variability– 40% RPS Scenario

Appendix F.3a: RPS Generation Variability – 33% RPS Target

Appendix F.3b: RPS Generation Variability – 40% RPS Scenario

Appendix F.4a: RPS Deliveries Variability – 33% RPS Target

## ~~1 Highlights of PG&E's 2014 RPS Plan~~

- Pacific Gas and Electric Company ~~(~~(“PG&E~~) filed a draft of~~”) respectfully submits its ~~2014 Renewable Energy Procurement Plan (RPS Plan or Plan) on June 4, 2014, and updated its Draft RPS Plan on August 20, 2014. In Decision (D.) 14-11-042, issued November 20, 2014,~~2015 Renewables Portfolio Standard (“RPS”) Plan to the California Public Utilities Commission ~~(~~(“CPUC” or “Commission~~) conditionally approved the 2014 RPS Plan and~~ ”) as directed ~~PG&E to file a final, conforming 2014 RPS Plan~~ by ~~December 8, 2014. The Commission suspended PG&E’s request to make modifications in the December 8, 2014 version of the 2014 RPS Plan. Accordingly, PG&E is filing this Final (Revision 1) 2014 RPS Plan to modify its request for modifications.~~

- ~~To the extent PG&E has a need for incremental Renewables Portfolio Standard (RPS)-eligible resources, PG&E intends to procure steady and moderate incremental long-term resources over the next several years to ensure that it can reach, and sustain, the 33% RPS targets and to maintain an adequate bank of surplus RPS volumes that ensures PG&E achieves the State’s policy objectives in a cost-effective manner.~~

- ~~Based on May 2014 forecasts and expectations of the ability of contracted resources to deliver, PG&E projects that it will meet its second (2014-2016) Compliance Period RPS requirements. However, before applying excess procurement from the first and second compliance periods, PG&E anticipates a small physical net short position for the third (2017-2020) Compliance Period RPS requirements.~~

- ~~PG&E’s RPS procurement efforts are currently focused on contracts that provide compliance value in 2020 and later. PG&E is seeking offers for resources that deliver in 2020 or later.~~

- ~~PG&E’s 2014 RPS Solicitation Protocol seeks to procure between zero and 1,600 gigawatt-hours (GWh) per year from offers meeting any of the three portfolio content categories within the statutory limitations for each category. PG&E seeks long-term or otherwise bankable RPS-eligible products because such products will help to sustain 33% beyond 2020 and because they provide the flexibility to optimize PG&E’s RPS portfolio over time. PG&E’s Solicitation will focus on procuring economically attractive products that fit PG&E’s portfolio need in order to maximize the value to our customers and minimize the cost of the RPS program.~~

- ~~In addition, this 1,600 GWh amount includes any incremental volumes that may come from any proposed new or additional renewables procurement mandates. Thus, if new long-term procurement mandates equaled, for example, 1,600 GWh, PG&E’s long-term procurement need for 2020 and beyond in the 2014 RPS Plan would be reduced to zero.~~

- ~~PG&E will rely primarily on established competitive solicitations (e.g., annual RPS Solicitations) to procure incremental renewable resources. This policy is designed to lower costs for customers and to provide the same procurement channels for all developers. Programs focused on mandated procurement of certain technologies or on projects~~

~~within a specific size range do not optimize RPS costs for customers and do not serve as an efficient procurement mechanism.~~

- ~~Generators with contracts expiring beyond the next few years will be actively encouraged to submit offers in upcoming solicitations for extensions that qualify as bankable under the California~~ the Assigned Commissioner ~~Public Utilities Commission's (CPUC or Commission) RPS compliance rules to ensure competitiveness with the rest of the renewables market. Such offers may provide the best opportunity for these developers to secure long-term contracts.~~

- ~~PG&E's objectives for this RPS Plan are to both achieve and maintain RPS compliance beyond 2020 and to minimize customer cost within an acceptable level of risk. The Plan assesses, models, and manages compliance risk by maintaining a bank of surplus procurement (Bank) that is both prudent and necessary. PG&E plans to use its Bank~~ [redacted] ~~as its voluntary margin of procurement (VMOP). Using the Bank as VMOP aims to mitigate the multiple dynamic risks and uncertainties that impact PG&E's RPS position. As the model results described in Section 7 show, a Bank is necessary in order to: (a) mitigate risks associated with short-term variability in load, (b) protect against project failure or delay exceeding forecasts, and (c) manage variability from RPS resource generation. This, in turn, enables PG&E to avoid long-term over-procurement above the 33% target after 2020 by utilizing the Bank to manage the year-to-year variability from these dynamic risks.~~

- ~~The costs associated with ensuring ongoing operational reliability while adding many new intermittent resources through the RPS program must be addressed and minimized. PG&E's 2014 RPS Solicitation Protocol supports the operational flexibility needed by the California Independent System Operator (CAISO) to address such costs by proposing contractual terms that allow PG&E to economically bid RPS resources into CAISO markets. PG&E has also incorporated into its 2014 RPS Solicitation Protocol the interim renewable integration cost adder approved by the Commission in D.14-11-042.~~

# ~~2 Executive Summary of PG&E's 2014 RPS Plan~~

## ~~2.1 Introduction~~

~~PG&E's 2014 RPS Plan describes the actions that PG&E will undertake to meet California's 33% RPS mandate and associated interim RPS requirements through procurement from resources that meet the RPS eligibility standards. The Draft Plan conditionally approved by the Commission was based upon data available as of May 2014. Users of this document should~~

~~understand that the conclusions and analysis in this Plan are generally based upon this May 2014 vintage of data.~~

~~PG&E is committed to achieving California's RPS goals. PG&E is well-positioned to meet the 33% RPS mandate and preliminary estimates show that PG&E met its first (2011-2013) Compliance Period RPS requirement of an average of 20% deliveries over that period. PG&E also projects that it will meet its second (2014-2016) Compliance Period requirements and it will have a small open position for the third (2017-2020) Compliance Period RPS requirements before applying excess procurement from the first and second compliance periods. Based upon the compliance outlook provided in this Plan, PG&E's 2014 RPS Solicitation (2014 RPS Solicitation) will focus on cost-effective procurement intended primarily for contracts that provide compliance value in 2020 or later, in order to position PG&E to be able to achieve and satisfy an ongoing 33% RPS requirement.~~

~~Despite the significant progress towards RPS compliance noted in this document, the Plan also explains the complexity and uncertainty inherent in renewables development, in forecasting operational performance, and in forecasting retail sales. Accordingly, the Plan describes an expected and risk-adjusted scenario to address potential RPS compliance outcomes and to mitigate dynamic risks and uncertainties inherent in achieving and sustaining RPS compliance. PG&E plans to use a bank of excess RPS-eligible procurement (Bank) primarily to address these dynamic risks and uncertainties, and thus plans to use its Bank primarily as a voluntary margin of procurement. In addition, PG&E's present deterministic forecast results serve to mitigate the RPS-eligible project failure and delay concerns that are the focus of the RPS statute's mandatory minimum margin of procurement.~~[1]

[1] ~~*See* Cal. Pub. Util. Code §§ 399.13(a)(4)(D), 399.15(b)(5)(B)(iii).~~

### ~~2.2 2014 Plan Objectives~~

~~The Plan reflects PG&E's current primary objectives with regard to RPS procurement, which include:~~

- ~~Addressing, as one step in a multi-year procurement strategy, a forecasted need for incremental, long-term RPS-eligible deliveries beginning in 2020 and onwards to better ensure that PG&E can reach, and sustain, the 33% RPS targets.~~
- ~~Ensuring that dynamic risks and uncertainties that could impact PG&E's RPS position are quantitatively assessed and incorporated in a robust procurement strategy that minimizes customer costs within an acceptable level of non-compliance risk.~~
- ~~Ensuring that PG&E has adequate flexibility to adapt a procurement strategy and contract language as net short assumptions, the market, and the regulatory landscape change.~~
- ~~Relying primarily on established competitive solicitations (e.g., the annual RPS Solicitations) to procure incremental renewable resources. This policy is designed to lower costs for customers and to provide the same procurement channels for all developers.~~
- ~~Evaluating proposed material amendments (i.e., those needed to preserve the viability of a project) or extensions to existing contracts against current offers for new resources.~~
- ~~Encouraging generators with contracts expiring in 2020 and beyond to submit offers in upcoming solicitations for extensions that qualify as bankable under the California **Public** Utilities Commission's (Commission) RPS compliance rules to ensure competitiveness with the rest of the renewables market.~~
- ~~Identifying the cost impacts of the RPS Program and mitigating them whenever possible, particularly when entering into incremental long-term commitments. Customer costs are impacted by both the direct procurement of renewable resources and the indirect costs, including any associated incremental transmission costs.~~
- ~~Addressing and minimizing the costs associated with ensuring ongoing operational reliability while adding many new intermittent resources through the RPS Program.~~

### ~~2.3 Overview~~

~~The Plan was developed in a manner consistent with the framework specified in the March 26, 2014 ACR[2] and the specific requirements of Public Utilities Code (Pub. Util. Code) Section 399.13 (a)(5)(A)-(F), including discussion of:~~

1) ~~Annual and multi-year supply and demand in relation to RPS requirements, the RPS Program, and the RPS Program's overall goals to determine the optimal mix of RPS resources with deliverability characteristics and any additional factors such as ability and/or willingness to be curtailed, operational flexibility, etc.~~

2) ~~A status update of the development schedule of all eligible renewable energy resources currently under contract.~~

3) ~~Potential compliance delays.~~

4) ~~An assessment of the risk that an eligible renewable energy resource will not be built or that its construction will be delayed, with the result that the electricity will not be delivered as required by the contract.~~

5) ~~A summary of the various demand-side and supply-side risks that impact PG&E's renewables portfolio, and the quantitative analysis that PG&E uses to address these risks and support its procurement decisions.~~

6) ~~Description of the assumed minimum margin of procurement above the minimum level necessary for compliance.~~

7) ~~A bid solicitation setting forth the need for ERRs of each deliverability characteristic, required online dates, and any locational preferences.~~

8) ~~Consideration of mechanisms of price adjustments associated with the cost of key components for renewable energy resource projects with online dates more than 24 months after the contract execution date.~~

9) ~~Cost forecasts of already-executed RPS contracts and forecasts of additional procurement needed to fill PG&E's identified long-term compliance need.~~

10) ~~A list of contracts expected to expire in the next 10 years.~~

11) ~~Responses to Renewable Net Short (RNS) Questions set forth in the May 21, 2014 Administrative Law Judge (ALJ) Ruling~~ in this proceeding~~.~~

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~~[2] "Assigned Commissioner's Ruling Identifying Issues and Schedule of Review for 2014 Renewables Portfolio Standard Procurement Plans," issued March 26, 2014 in Rulemaking (R.) 11-05-005.~~

~~2.~~4 ~~RPS~~ in the *Assigned Commissioner's Revised Ruling Identifying Issues and Schedule of Review for 2015 Renewable Portfolio* ~~Supply and Demand~~*Standard Procurement Plans* ("ACR") issued on May 28, 2015. PG&E's 2015 RPS Plan includes a summary of key issues and important legislative and regulatory developments impacting California's RPS requirements, and then addresses each of the specific requirements identified in the ACR.[3] PG&E believes its 2015 RPS Plan satisfies all of the statutory and Commission requirements and addresses key policy issues that have arisen as the renewable energy industry matures and grows in California.

~~This Plan demonstrates that while PG&E is well-positioned to meet its near-term RPS compliance requirements and has made significant progress toward increasing its procurement of renewable resources in the last several years, PG&E will continue procuring RPS-eligible products to satisfy its ongoing 33% RPS requirement.~~[4] ~~As discussed throughout this Plan and more specifically in Sections 3 and 7, PG&E currently projects that it will be in compliance during the interim Compliance Periods leading to an ongoing 33% RPS requirement. Recognizing the amount of time required to develop renewable energy projects and the potential for future project failures, PG&E's plan is to continue with its multi-year strategy to procure modest volumes each year, focused on purchasing for longer-term needs, which will enhance PG&E's ability to satisfy an ongoing 33% RPS requirement post-2020.~~

~~The ability of PG&E to meet its 33% mandate is highly dependent on the ability of the counterparties with which PG&E has Power Purchase Agreements (PPA) to successfully develop their RPS projects. Over the past year, PG&E has experienced increasing success in its counterparties' abilities to do so, and~~

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3 *See* ACR, pp. 8-20.

4 ~~RPS-eligible resources will be determined based on the most current California Energy Commission RPS Eligibility Guidebook, released in its 7th edition in April 2013.~~

~~now expects a significant number of projects to come online in the 2014-2015 period. Therefore, the RPS need calculated in the 2014 RPS Plan reflects a high rate of success for PG&E's existing portfolio of projects under development. This development, along with additional changes in the California renewable energy landscape, is discussed in greater detail in Sections 3 and 5.~~

~~In addition, PG&E will have a number of expiring contracts in coming years, which are described in more detail in Section 12. Some of these expiring contracts with existing RPS-eligible generators may be available for re-contracting and may be re-contracted for if there is an RPS need and if offered at competitive prices. New contracts with existing facilities will be considered along with contracts for new facilities.~~

~~To the extent that the regulatory or financial environment changes in a way that decreases the likelihood of success for projects in PG&E's portfolio that are under contract but not yet in operation, or that threatens the viability of existing projects, PG&E's projected incremental RPS need also will change. Accordingly, the RPS need set forth in this Plan is based on a series of dynamic assumptions that will change. With each future RPS Procurement Plan, and as needed as part of advice letter filings seeking approval of individual RPS procurement contracts, PG&E will update its need demonstration.~~

~~PG&E's demand for RPS resources is a function of multiple complex factors including regulatory requirements and portfolio considerations. In addition, the demand forecast is a function of the risk factors discussed in more detail in Section 6. Uncertainty around bundled retail sales can have a major impact on PG&E's demand, as further detailed in Section 3.~~

### ~~2.5 Potential Compliance Delays~~

~~While PG&E is committed to meeting California's RPS mandate, achieving these ambitious renewable energy goals presents challenges. As described in further detail in Section 5, PG&E's ability to comply with the RPS~~

~~procurement requirement targets remains contingent on a number of factors outside of PG&E's control, including the ability of independent power producers that have executed PPAs with PG&E to overcome development challenges. Equally important, the operational reliability challenges created by adding a large amount of new intermittent resources to the California electric grid must be addressed. Specifically, the anticipated costs of integrating the various RPS resource types need to be explicitly captured in the evaluation and selection process in the future, including addressing the need for flexible capacity. Solving these grid integration challenges in an efficient and economic manner is vital to providing PG&E's customers with safe, cost-effective, and reliable electric service.~~

~~The timely development of renewable energy generation facilities is subject to many uncertainties and risks, including regulatory and legal uncertainties, permitting and siting issues, securing financing, technology, fuel supply, and the construction of sufficient transmission capacity. Uncertainty around the future of the Production Tax Credit (PTC) and the Investment Tax Credit (ITC) can create price and financing uncertainty for projects. These factors and others discussed in Section 5 may require PG&E to seek a reduction in its portfolio content requirements or a waiver of its overall RPS procurement requirements, as provided for in Sections 399.15(b) (5) and 399.16(e) of the Pub. Util. Code.~~

## ~~2.6 Determining RPS Need~~

~~Considering the complex and variable dynamics driving the outlook for supply and demand, PG&E employs two models – a deterministic model on portfolio assessment and a stochastic model on compliance risk – to determine its RPS position and to develop its procurement plan in order to optimize cost, value and risk for the ratepayer while achieving RPS compliance. Sections 6 and 7 describe these models and their findings. PG&E relies on these models in~~

~~its determination of a procurement strategy to achieve RPS compliance within an acceptable level of risk. These models consider multiple factors and risks affecting the supply of and demand for RPS products that drive RPS deliveries and PG&E's RNS position. The procurement goal for the 2014 RPS Plan was derived with the help of these models.~~

~~In order to achieve PG&E's RPS objective in the most cost-effective manner, PG&E maintains two margins of procurement: (1) a statutory margin of procurement to address some anticipated project failure or delay – both for existing projects and projects under contract but not yet online; and (2) a VMOP. PG&E plans to use its Bank, which is described in greater detail in Sections 6, 7, and 8,~~ [redacted] ~~as its VMOP.~~[5] ~~Using the Bank as VMOP mitigates the additional risks and uncertainties that are accounted for in PG&E's modeling. As the modeling in later sections of this Plan shows, such a Bank is necessary in order to (a) mitigate risks associated with short-term variability in load, (b) protect against project failure or delay exceeding forecasts, and (c) manage variability from RPS resource generation. This, in turn, enables PG&E to avoid long-term over-procurement above the 33% target after 2020 by utilizing the Bank to manage the year-to-year variability from these dynamic risks.~~

## ~~2.7 PG&E's 2014 Procurement Goal~~

~~PG&E's procurement goal for its 2014 RPS Solicitation, reflected in the 2014 RPS Solicitation Protocol and supported by the Plan's RPS need quantification, is to add to its RPS portfolio between zero and 1,600 GWh per year of RPS-eligible deliveries offering high portfolio value through long-term contracts providing compliance value in 2020 and beyond. These volumes~~

[5] ~~This VMOP is in addition to the minimum margin of procurement accounted for in PG&E's risk adjusted RPS forecast in the deterministic model. Additional detail is provided in Section 7.~~

~~would be in addition to any volumes PG&E procures through the Renewable Auction Mechanism (RAM) Program, the Feed-In Tariff (FIT) programs, RPS-eligible projects within the Combined Heat and Power/Qualifying Facility (CHP/QF) Program, or the Photovoltaic (PV) Program. PG&E assumes in this Plan that these mandatory procurement programs deliver 100% of their approved volumes.~~

~~PG&E will rely primarily on existing competitive procurement processes to meet its incremental RPS procurement needs. PG&E believes that relying primarily on these established competitive solicitation processes will lower costs for customers and provide fair opportunities for all developers to offer cost-competitive renewable products that fit PG&E's portfolio need.~~

### ~~2.8 Bid Solicitation and PPA~~

~~PG&E's 2014 RPS Solicitation seeks RPS-eligible products that will enable PG&E to comply with its RPS obligations.~~[6] ~~PG&E's Bid Solicitation Protocol is revised to reflect 2014 RPS procurement goals. PG&E does not envision major changes to the general solicitation process for 2014. As explained further in Chapter 9 and the 2014 RPS Solicitation Protocol at Appendix H, PG&E will seek long-term offers from all three product content categories with a preference for 10- or 15-year contract tenor. Projects in PG&E's service territory are preferred, as are projects with characteristics that merit a higher viability score. Out-of-state offers will continue to be evaluated based on the type of product they offer, assuming such offers can contribute toward PG&E's RPS need as reflected in Section 7 and Appendix C.~~

~~The offers selected will have the best combination of market value, Portfolio Adjusted Value (PAV), viability, and qualifications, based on the~~

[6] ~~Projects may also elect to provide Resource Adequacy (RA) and/or energy storage target compliance values.~~

~~evaluation criteria specified in the 2014 Solicitation Protocol. Additionally, PG&E will evaluate the project viability of each offer using the June 2, 2011 CPUC Project Viability Calculator (PVC).~~

~~As discussed throughout this 2014 RPS Plan and more specifically in Section 9, PG&E has made changes to the 2014 RPS Form PPA and 2014 RPS Solicitation Protocol. These changes reflect changing market conditions and PG&E's RPS need, and are intended to create greater incentives for full contract performance. PG&E does not envision major changes to the general solicitation process for 2014. PG&E may make modifications to the 2014 Solicitation Protocol and 2014 RPS Form PPA as market conditions evolve prior to solicitation issuance.~~

### ~~2.9 Utility-Ownership of RPS Resources and Renewable Investments~~

~~PG&E is not seeking bids for Purchase and Sale Agreements or sites for Utility-Owned Generation (UOG) through this 2014 RPS Plan. Nonetheless, PG&E is open to considering bilateral offers for exceptional opportunities to build renewable generation or to invest in renewables that are cost-effective relative to other procurement options and present high value to customers. PG&E will follow the process identified in its Long-Term Procurement Plan (LTPP) for submitting any additional RPS-eligible UOG for approval by the Commission. PG&E continues to include utility-owned small hydroelectric generation and PV generation in the Plan's RPS procurement and cost forecasts.~~

~~All 150 MW[7] from PG&E's PV UOG Program from program years 1, 2, and 3 are now online. In D.14-11-026, issued on November 21, 2014, the Commission approved PG&E's request to terminate the PV Program after program year 3.~~

~~7 This is in addition to the 2 MW Vaca-Dixon Solar Station PV pilot project, which came online in 2010.~~

~~**2.10 Sales of RPS Procurement**~~

1 ~~**PG&E's RPS net short and cost projections include any sales of contracted deliveries. Over the last year, PG&E has entered into a number of contracts to sell excess RPS procurement.**~~ [redacted]

**Summary of Key Issues**

**1.1 PG&E's RPS Position**

PG&E projects that under both the current 33% RPS by 2020 target, as well as a 40% by 2024 scenario, it is well-positioned to meet its RPS compliance requirements for the second (2014-2016) and third (2017-2020) compliance periods and will not have incremental procurement need until at least 2022. Under the current 33% RPS target, PG&E projects that it will have incremental procurement need beginning in [redacted], after applying banked volumes of excess procurement ("Bank") beginning in [redacted]. Under the 40% RPS by 2024 scenario, PG&E projects that it will have incremental procurement need beginning in [redacted], after applying Bank beginning in [redacted]. In both situations, PG&E anticipates additional steady, incremental long-term procurement in subsequent years to avoid the need to procure large volumes in any single year to meet compliance needs and maintain minimum Bank levels.

**1.2 PG&E Proposes Not to Hold a Request for Offers in 2015**

Given its current RPS compliance position, PG&E proposes not to hold an RPS solicitation in 2015. PG&E has sufficient time in the coming years to respond to changing market, load forecast, or regulatory conditions and will reassess the need for future solicitations in next year's RPS Plan. Although many factors could change its RPS compliance position, PG&E believes that its existing portfolio of executed RPS contracts, its owned RPS-eligible generation, and its expected Bank balances will be adequate to ensure compliance with near-term RPS requirements. Additionally, PG&E expects to procure additional volumes of incremental RPS-eligible contracts through mandated procurement programs in 2016.[8] In 2016, PG&E will reassess its Renewable Net Short ("RNS") position and determine its updated procurement needs. PG&E's proposal not to hold a 2015 RPS solicitation is consistent with a proposal made by San Diego Gas & Electric Company ("SDG&E") in its 2014 RPS Plan, and approved by the Commission given SDG&E's lack of need.[9]

### 1.3 Consideration of Higher RPS Targets Should Be Integrated With Broader State Greenhouse Gas Goals

California's RPS has played, and will continue to play, an important role in lowering electric sector greenhouse gas ("GHG") emissions and meeting the state's clean energy goals. PG&E supports maintaining the existing requirements that load-serving entities ("LSE") provide a minimum of 33% RPS in 2020 and beyond. As the state looks beyond 2020, however, PG&E believes California's clean energy policy should be centered on achieving the most cost-effective GHG reductions needed to meet the Governor's 2030 goal of emissions that are 40% of 1990 levels.[10]

Before taking any action that would increase the RPS requirements, the Commission should consider how the RPS program fits within a comprehensive GHG policy framework built to achieve emissions reductions through a combination of actions, as opposed to potentially inefficient carve-out mechanisms.[11] Renewable energy policy should be more completely aligned with this broader policy context in order to ensure that GHG reduction targets are achieved in an integrated and economically efficient manner. Rather than reflexively raise the RPS targets, the CPUC

8 Mandated programs include Renewable Auction Mechanism ("RAM"), Renewable Market Adjusting Tariff ("ReMAT"), and Bioenergy Market Adjusting Tariff ("BioMAT"). In addition, while not pursuant to the RPS mandate, PG&E expects to procure additional volumes over the next year for the Green Tariff Shared Renewables Program ("GTSR").

9 Decision ("D.") 14-11-032, p. 32, Ordering Paragraph ("OP") 17.

10 Office of California Governor Edmund G. Brown, Executive Order 4-29-2015 (available at http://gov.ca.gov/news.php?id=18938).

11 For further discussion of the cost impacts of mandated procurement programs, see Section 13.3.

should adopt a strategy focused on flexibility, equitable rules for all LSEs, affordability, and market and system stability.[12]

### 1.4 Renewable Portfolio Growth Increases Customer Rate Impacts

As a part of this RPS Plan, PG&E is providing [redacted] ~~PG&E's 2014 RPS Solicitation Protocol contains a new appendix for a pro forma agreement for the sale of RPS-eligible products with a term of 5 years or less, as authorized by D.14-11-042.~~

### ~~2.11 RPS Program Costs~~

~~PG&E provides~~ historic and forecasted RPS cost and rate information ~~as part of the Plan. The standardized methodology is described in Section 11 and the template included in Appendix D.~~. From 2003 ~~to 2014~~ 2015, PG&E's annual RPS-eligible ~~and approved~~ procurement and generation costs have continued to increase~~, from $523 million in~~. The costs of the RPS Program have already and will continue to impact customer bills. From 2003 ~~to approximately~~ [redacted] ~~expected for 2014. That number is expected to rise to $2.8 billion by 2017. The~~ 2016, PG&E estimates its annual rate impact from RPS procurement has increased from 0.7 cents per

12 For further discussion, see PG&E's opening and reply comments in response to *Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program (R.15-02-020)* filed on March 26, 2015 and April 6, 2015, respectively.

kilowatt-hour ("¢/kWh") in 2003 to an estimated 3.5¢/kWh in 2016.[13] The growth in rates due to RPS procurement costs will continue to increase through 2020, as the average rate impact is forecasted to increase to 3.9¢/kWh, or approximately $2.3 billion. Further detail regarding RPS costs is provided in Section 13 and the annual rate impact of forecasted procurement is detailed in Table ~~-~~ 2 of Appendix D~~, illustrating that the average~~.

To address these rate ~~impact~~impacts, PG&E's procurement strategy attempts to minimize cost and maximize value to customers, while satisfying the RPS program requirements. To accomplish this goal, PG&E promotes competitive processes to procure incremental RPS volumes, strategically uses its Bank, and avoids long-term over-procurement.

As described above, a more integrated GHG policy framework that enables LSEs to adapt to changing needs, costs, and circumstances and manage the integration of variable resources would provide additional opportunities to lower customer costs. New technologies will emerge and the mix and cost-effectiveness of GHG emissions reduction strategies will undoubtedly evolve over the next several years. PG&E believes that a more flexible implementation of the RPS Program that allows LSEs to optimize a portfolio of different GHG reduction strategies would facilitate meeting the State's environmental goals at the lowest possible costs and best portfolio fit, and provide the maximum benefits to customers. Similarly, as discussed in Section 13.3, mandated procurement programs within the RPS reduce the program's efficiency while increasing costs.

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13 "Annual Rate Impact" should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable "premium." In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

### 1.5 PG&E's Bank Is Necessary to Ensure Long-Term Compliance

PG&E views its Bank as necessary to: (1) mitigate risks associated with ~~RPS-eligible resources is~~variability in load; (2) protect against project failure or delay exceeding forecasts; and (3) avoid intentional over-procurement above the 33% RPS target by managing year-to-year generation variability from performing RPS resources. The Bank allows PG&E to mitigate the need to procure additional RPS products at potentially high market prices in order to meet near-term compliance deadlines. With an adequate Bank, PG&E aims to minimize customer cost by having the flexibility not to procure in "seller's market" situations. More information on forecasted ~~to increase to~~ [redacted]~~/kWh in 2017, up from~~ [redacted]~~/kWh in 2014~~Bank size and ~~0.7 cents/kWh in 2003. Further detail regarding the methodology underlying Table 2 of Appendix D~~minimum Bank levels under both 33% and 40% RPS is provided in Section ~~11~~ 7 below.

> ~~As described in more detail below, PG&E's strategy is to minimize the overall cost impact of renewables over time by promoting competitive processes, using the Bank to help avoid long-term over-procurement that could place volumetric pressure on the total dollar impact from renewables, and considering opportunistic, economically-attractive near-term offers when appropriate.~~

PG&E will continue to assess the value to its customers of sales of surplus procurement. Currently, PG&E's RNS, future RPS cost projections, and assessment of the current Renewable Energy Credit ("REC") market do not lead to an expectation of material projected sales of RECs. However, PG&E will consider selling surplus non-bankable RPS volumes and may consider selling surplus bankable volumes if it can still maintain an adequate Bank and if market conditions are favorable.

### 1.6 RPS Rules Should Be Applied Consistently and Equitably Across All LSEs

PG&E's long-term position is a forecast based on a number of assumptions, including a certain amount of load departure due to Community Choice Aggregation ("CCA") and distributed generation growth. While it is possible that this forecasted load departure may not fully materialize or occur at the rate assumed in the forecast, PG&E's forecast is a reasonable scenario based on current trends. Under the existing percentage-based RPS targets, any departure of PG&E's load to CCAs naturally results in both a reduction of PG&E's required RPS procurement quantities and a corresponding increase in RPS procurement by CCAs. Thus, CCAs will be required to shoulder an increasing portion of the State's RPS procurement goals. The consistent and equitable application of all RPS rules and requirements to all Commission-jurisdictional LSEs, including CCAs and Electric Service Providers ("ESPs"), will help to ensure that all LSEs are helping California achieve its ambitious renewable energy goals.

## ~~2.12~~2 Summary of Important Recent Legislative/Regulatory Changes to the RPS Program

~~PG&E's procurement goals outlined in detail throughout this Plan reflect the current RPS Program requirements.~~ PG&E's portfolio forecast and procurement decisions are influenced by ongoing legislative and regulatory changes to the RPS ~~program~~Program. The following is a description of recent changes to the RPS Program ~~over the past year~~ that ~~highlights the policy considerations impacting~~have impacted PG&E's RPS procurement ~~decisions.~~ .

### ~~2.12.1~~ Commission Implementation of ~~SB 2 (1x)~~

### 2.1 Senate Bill ~~(~~2 (1x)

Senate Bill ("SB~~)~~") 2 (1x), enacted in April 2011 and effective as of December 11, 2011, made significant changes to the RPS Program, most notably extending the RPS goal from 20% of retail sales of all California investor-owned utilities ~~(IOU), Energy Service Providers (ESP),~~("IOUs"), ESPs, publicly-owned utilities ("POUs"), and ~~Community Choice Aggregations (CCA)~~CCAs by the end of 2010, to a goal of 33% of retail sales ~~of IOUs, ESPs, CCAs, and publicly-owned utilities~~ by 2020. The Commission issued an Order Instituting Rulemaking to implement SB 2 (1x) in May 2011 and has subsequently issued ~~several~~a number of key decisions implementing certain “high priority” issues needed to implement the complex provisions of SB 2 (1x). ~~Implementation is~~In February 2015, the Commission opened a new rulemaking (R.) 15-02-020 to address remaining issues from this earlier proceeding, as well as other elements of the ongoing~~, and~~ administration of the RPS Program. Commission action on remaining and new key issues may impact PG&E’s procurement need and actions going forward, notwithstanding the forecasts and projections included in this Plan.

### ~~2.12.1.1 Compliance Rules~~

~~A number of~~Key Commission ~~Decisions have already been~~decisions issued ~~as part of the implementation of~~to date implementing SB 2 (1x~~), including Decision (~~) include D.~~)~~.11-12-052 which defined portfolio content categories~~,~~ (“PCC”), D.11-12-020 which outlined compliance period targets for the 33% RPS ~~goal~~target, and D.12-06-038 which implemented changes to the RPS compliance rules for retail sellers, including treatment of prior procurement to meet RPS obligations for both the 20% and 33%~~-~~ RPS Programs. D.12-06-038 also adopted rules on calculating the RPS ~~bank, on~~Bank, meeting the portfolio balance requirements, and for reporting annually to the Commission on RPS procurement. ~~On September 27, 2013~~Finally, on December 4, 2014, the CPUC ~~released an ALJ ruling requesting comments on~~ adopted D.14-12-023 setting RPS compliance and enforcement ~~issues related to the RPS program, including penalties and penalty caps for noncompliance with RPS procurement requirements. In its January 13, 2014 Third Amended Scoping Ruling, the CPUC indicated that a Proposed Decision on compliance and enforcement is expected in 2014.~~ rules under SB 2 (1X).

### ~~2.12.1.2~~2.2 Cost Containment

When California’s legislature passed SB 2 (1x~~) requires~~), it required the CPUC to develop a limitation on total RPS costs for each electrical corporation. The legislature specified that the cost limitation must prevent the 33% RPS ~~from causing “disproportionate rate impacts.” PG&E has been working with the Commission and stakeholders to develop an effective Procurement Expenditure Limitation that mitigates~~

~~RPS-related costs and their effects. The Commission issued an initial Staff Proposal for a procurement expenditure limitation for the RPS program on July 23, 2013 and held a workshop on November 20, 2013. On February 20, 2014, the Commission released a revised Staff proposal, along with updated alternative proposals. PG&E submitted opening comments and reply comments in response to the revised proposal. According to the January 13, 2014 Third Amended Scoping Ruling, a Proposed Decision is expected in the second quarter of 2014. PG&E believes the Procurement Expenditure Limitation should be clear, stable, and meaningful in order to promote regulatory certainty and support procurement planning~~target from causing "disproportionate rate impacts." If PG&E exceeds the Commission-approved cost cap, it may refrain from entering into new RPS contracts and constructing RPS-eligible facilities unless additional procurement can be undertaken with only "de minimis" rate impacts.

~~**2.12.1.3 Procurement Reform**~~

~~In April 2012, the Commission issued an Assigned Commissioner Ruling Identifying Issues and Schedule of Review for 2012 RPS Procurement Plans, providing several new proposals related to renewable energy procurement reform. In October 2012, a second Assigned Commissioner Ruling was issued, offering additional proposals to refine the RPS procurement process. On April 8, 2014, the Commission issued a Staff Proposal to reform the review process for the RPS contracts, to which PG&E submitted comments. In Opening Comments submitted on May 7, 2014, PG&E raised concerns over the proposed data adequacy requirements, as they are duplicative of work done by other agencies and may usurp those~~

~~agencies' permitting role.[14] PG&E also requested that the proposed 60-day deadline for submission of shortlists in the annual RPS solicitation be extended to 120 days following the close of bidding in the solicitation, and that the shortlist be submitted in the form of a Tier 2, not Tier 3 Advice Letter.[15] The Commission resolved these issues in its decision on the 2014 RPS Plans, D.14-11-042.~~

~~The Commission also plans to issue in 2014 an ALJ ruling and revised staff proposal to reform the LCBF methodology for evaluating RPS procurement opportunities.~~

**~~2.12.1.3.1 Renewable Net Short~~**

~~PG&E's RPS Plan includes a calculation of its Renewable Net Short position, per the instruction of the Commission. On August 2, 2012, the Commission issued a ruling with a renewable net short methodology for IOUs to include in their 2012 RPS procurement plans. IOUs were advised to use the same methodology in their 2013 and 2014 RPS Plans. On February 19, 2014, the Commission issued a proposal for modifications to the RNS methodology. PG&E submitted opening and reply comments on March 7, 2014 and March 20, 2014, respectively. On May 21, 2014, the Commission issued an ALJ Ruling on Renewable Net Short that outlined a revised RNS~~

[14] ~~Pacific Gas and Electric Company's Opening Comments on April 2014 Staff Proposal for RPS Procurement Reform, filed on May 7, 2014 in R.11-05-005, p. 7 (available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M090/K936/90936699.PDF).~~

[15] ~~*Id.*, p. 8.~~

~~methodology and instructed retail sellers to calculate their RNS based on the new methodology for all future RPS Plans. That table can be found in Appendix C.1. As further described in Section 7, PG&E is also providing an alternative RNS calculation that more fully reflects its internal optimization strategy in Appendix C.2. The Ruling also included a list of eleven questions to be included in the RPS Plans. PG&E is providing responses to those questions in Appendix J.~~

PG&E has made every effort to procure least-cost and best-fit renewable resources. However, recognizing the potential cost impact that RPS procurement can have on customers, PG&E strongly supports the establishment of a clear, stable, and meaningful Procurement Expenditure Limitation ("PEL") that both informs procurement planning and decisions, and promotes regulatory and market certainty. PG&E urges the Commission to finalize the PEL as soon as possible, given that the RPS statute requires the Commission to report by January 1, 2016 on the status of each IOU in achieving 33% RPS within the adopted PEL, and to propose any necessary modifications to the PEL.

### ~~2.12.2~~2.3 Implementation of Bioenergy Legislation

~~The CPUC is currently implementing SB 1122, which was signed into law on~~On September 27, 2012~~ and directs~~, SB 1122 was passed, requiring California's IOUs to procure 250 megawatts ~~(~~("MW~~)~~") in total of new small-scale ~~Bioenergy~~bioenergy projects 3 MW or less through the Feed-In Tariff ("FIT") Program. The total IOU program ~~megawatts~~MWs are allocated into three technology categories: 110 MW for biogas from wastewater plants and green waste~~,~~; 90 MW for dairy and other agriculture bioenergy; and 50 MW for forest waste biomass. The allocation of ~~megawatts~~MWs by project type for each IOU, as well as the program design, is being determined by the Commission in proceedings currently underway. PG&E has worked with the

Commission and stakeholders in order to ensure that the SB 1122 program is implemented in a way that balances the needs of the bioenergy industry with clear cost containment mechanisms that protect customers from excessive costs. On December 18, 2014, the Commission issued D.14-12-081 to implement SB 1122 and required the IOUs to file a tariff and contract for SB 1122 eligible generation. The IOUs filed their proposed contract and tariff on February 6, 2015.

~~On January 16, 2014, the Commission issued D.14-01-034 regarding the Biomethane Implementation Tasks in Assembly Bill (AB) 1900. On April 9, 2014, the Commission issued a Scoping Memo and Ruling outlining the second phase of the proceeding, which is intended to address the costs associated with the standards and requirements adopted in the first phase of the proceeding.~~

**~~2.12.3 Green Tariff Shared Renewables (GTSR) and Senate Bill 43~~**

~~On September 30, 2013, Governor Brown signed into law SB 43, or the California Shared Renewables Bill. The law requires that the three IOUs procure 600 MW of community-scale renewable projects of 20 MW or less by 2020, although 100 MW of that mandate have to be met by projects 1 MW or less. PG&E's share of the mandate is 272 MW. The bill enables the IOUs to leverage their existing proposals for voluntary renewable programs, and PG&E is accordingly using its previously-proposed GTSR (also known as Green Option) program as a basis for compliance with SB 43. PG&E filed the GTSR application (Application (A.)12-04-020) at the Commission on April 24, 2012 seeking authority to offer a voluntary program that provided an option for PG&E bundled customers to be 100% renewable through the use of unbundled RECs for the non-RPS-eligible portion of their bill (the GTSR).~~

~~On April 11, 2013, PG&E filed a joint settlement with a number of parties, making some modification to the program in order to address~~

~~party concerns with the application. Specifically, PG&E withdrew the unbundled Renewable Energy Credits (REC) component of its proposal in favor of a "steel in the ground" incremental renewable product for customers who choose to procure additional energy as part of their electricity services. This settlement served as the basis for SB 43 when the Commission began implementation of the legislation. The Commission consolidated PG&E's GTSR application with SDG&E's voluntary community renewables program application, and required SCE to submit a Green Tariff Shared Renewables program proposal that aligns with SB 43. All three applications have been consolidated into one proceeding, and the Commission will rule on whether these applications meet the requirements of SB 43. A decision is expected in July 2014.~~

~~Under its proposed GTSR program, PG&E may allocate relatively small portions of the output of specific generation resources, or entire resources, from its existing portfolio of operating RPS-eligible resources to serve the initial GTSR enrollees until new, incremental resources procured specifically for the GTSR commence operation to meet the program demand. If the Commission approves the GTSR as filed, PG&E would revise its Renewable Net Short (RNS) to account for the relatively small reduction in the compliance position at that time. Over the long-term, PG&E has proposed to procure incremental, GTSR-dedicated resources or portions of resources. These GTSR-dedicated resources would not be used for RPS compliance so long as they are dedicated to serving GTSR customers.~~

#### ~~2.12.4 Energy Storage~~

~~Assembly Bill (AB) 2514, signed into law in September 2010, added Section 2837 to the California Public Utilities Code, which requires~~

~~that IOUs' RPS procurement plans incorporate any energy storage targets and policies that are adopted by the Commission as a result of its implementation of AB 2514. The statute includes a deadline of October 1, 2013 for adoption of any appropriate energy storage targets, and the Commission has initiated R.10-12-007 to implement AB 2514. On October 17, 2013, the CPUC issued D.13-10-040 adopting an energy storage procurement framework and program design, requiring that PG&E execute 580 MW of storage capacity by 2020, with projects required to be installed and delivering by no later than end of 2024. In accordance with the guidelines in the decision, PG&E submitted an application to procure energy storage resources on February 28, 2014.~~

~~PG&E's 2014 RPS Solicitation Protocol encourages RPS offers with energy storage whose energy storage component can be counted towards the Commission's energy storage procurement targets.~~

~~PG&E will actively monitor CEC proceedings to update the RPS Eligibility Guidebook, in which the CEC may make further determinations regarding the eligibility of energy storage systems that can charge directly from the grid, and PG&E reserves the right to modify consideration of energy storage systems presented as a component of an RPS offer through the RPS Solicitation accordingly. PG&E's LCBF methodology, more fully described in Attachment K to Appendix H, takes into account additional value offered by RPS-eligible generation facilities that incorporate energy storage.~~

# 3 Assessment of RPS Portfolio Supplies and Demand

## 3.1 Supply and Demand to Determine the Optimal Mix of RPS Resources

Meeting California's ~~aggressive renewable energy~~RPS goals in a way that achieves the greatest value for customers continues to be a top priority for PG&E. In particular, PG&E ~~is working~~continues to analyze its need to procure cost-effective resources that will enable it to achieve ~~SB 2 (1x)'s increase in~~and maintain California's 33% RPS target~~ to 33% of delivered energy from RPS-eligible facilities. According to implementation guidelines of SB 2 (1x) in D.11-12-020, since~~. PG&E ~~met its statutory requirement of procuring at least 14% of retail sales as RPS-eligible resources, it is~~ is currently required to procure the following quantities of RPS-eligible products~~ beginning on January 1, 2011~~:

- 2011-2013 (First Compliance Period): 20% of the combined bundled retail~~-~~ sales~~ during the first compliance period (2011-2013).~~.
- 2014-2016 (Second Compliance Period): A ~~percent~~percentage of the combined bundled retail sales ~~during the second compliance period (2014-2016)~~ that is consistent with the following formula:~~–~~ (.217 * 2014 retail sales) + (.233 * 2015 retail sales) + (.25 * 2016 retail sales).
- 2017-2020 (Third Compliance Period): A ~~percent~~percentage of the combined bundled retail sales~~ during the third compliance period (2017-2020)~~ that is consistent with the following formula: (.27 * 2017 retail sales) + (.29 * 2018 retail sales) + (.31 * 2019 retail sales) + (.33 * 2020 retail~~-~~ sales).
- 2021 and beyond: 33% of combined retail sales in 2021 and each year thereafter.

Based on preliminary results presented in ~~PG&E's March 2014 Compliance Report~~Appendix C.2a, PG&E delivered ~~approximately 22.5%~~ 27.0% of its power from RPS-eligible renewable sources in ~~2013, ending the first compliance period with a slight surplus relative to its multi-year RPS compliance requirement.~~ 2014.

As described more fully in Section~~-~~ 7 and reported in the current RNS calculations in ~~Appendices C.1~~Appendix C.2a, based on forecasts and ~~C.2~~expectations of the ability of contracted resources to deliver, PG&E is well-positioned to meet its RPS compliance requirements for the second (2014-2016) and third (2017-2020) compliance periods. Under the current 33% RPS target, PG&E projects that it will not have incremental procurement need until at least 2022, with need beginning in [redacted], after applying Bank beginning in [redacted].

Under a 40% RPS scenario, PG&E modeled the same trajectory through 2020 as described above, but modeled the following RPS requirements starting in 2021:

- 33% of combined bundled retail sales in 2021;
- 37% of combined bundled retail sales in 2022;
- 37% of combined bundled retail sales in 2023; and
- 40% of combined bundled retail sales in 2024 and each year thereafter.

For this scenario, based on forecasts and expectations of the ability of contracted resources to deliver, PG&E projects that it ~~will~~ is well-positioned to meet its ~~second Compliance Period~~ RPS compliance requirements for the second (2014-2016~~). Before applying excess procurement from the first~~) and ~~second~~ third (2017-2020) compliance periods~~,~~. PG&E ~~anticipates a small RPS open position for the third (2017-2020) Compliance Period RPS requirements. PG&E intends to procure steady and moderate~~projects that it will have incremental ~~long-term resources over the next several years to ensure that it can reach, and sustain, the 33% RPS targets.~~ procurement need beginning in [redacted], after applying its Bank towards its physical net short beginning in [redacted].[16]

### ~~3.2 Supply – Existing Portfolio and RPS Market Trends~~

### 3.2 Supply

#### 3.2.1 Existing Portfolio

PG&E's existing RPS portfolio is comprised of a variety of technologies, project ~~capacities~~sizes, and contract types. The portfolio includes over 8,~~500~~000 MW of active projects, ranging from utility-owned solar and small hydro generation to long-term RPS contracts for large wind, geothermal, solar, and biomass ~~and~~ to small FIT contracts for solar photovoltaic ("PV~~,~~"), biogas, and biomass generation. This robust and diversified

16 This projection includes future volumes from mandated programs, such as the RAM and FIT Programs.

supply provides a solid foundation for meeting current and future compliance needs~~.~~ ~~However~~; however, the portfolio is also subject to uncertainties ~~such~~ as ~~curtailment levels~~discussed below and ~~generation variability. Additional insights into these uncertainties are provided~~ in ~~Section~~ more detail in Sections 6~~.~~ and 7.

As ~~is~~ described in further detail in Section ~~5, project success rates have improved significantly, although challenges remain. For~~ 7.1, for the ~~2014~~2015 RPS Plan, PG&E ~~has reduced the assumed~~assumes a volumetric success rate for all executed~~-but-not-yet-operational~~ in-development projects in its RPS portfolio ~~to~~of approximately ~~87~~99% of total contracted volumes. ~~While this is a slight reduction from the 100% success~~ This rate ~~described in the 2013 RPS Plan, success rates overall continue to~~ continues its general trend ~~upwards (87% is an increase from 78% its 2012 RPS Plan, and an increase~~of increasing from 60% in RPS Plans prior ~~plans).~~to 2012, to 78% in PG&E’s 2012 RPS Plan, to 100% in PG&E’s 2013 RPS Plan, and 87% in PG&E’s 2014 RPS Plan. This success rate is evolving and highly dependent on the nature of PG&E’s portfolio ~~and~~, the general conditions in the renewable energy industry~~.~~, and the timing of the RPS Plan publication date relative to recent project terminations. While PG&E has continued to see a general trend towards higher project success rates, the change in its ~~revised~~ success rate assumption from 2014 to 2015 (from 87% to 99%) reflects the ~~addition~~recent removal of several projects from PG&E’s portfolio due to contract terminations and an update to the “Closely Watched” category described in Section 6.

Consistent with the project trends reported in its ~~2013~~2014 RPS Plan, PG&E has observed continued progress of key projects under development in ~~PG&E’s~~its portfolio. Tax incentives (e.g., the federal Investment Tax Credit (“ITC ~~and the federal PTC)~~”) and ~~the expired stimulus subsidies available through the American Recovery and Reinvestment Act of 2009 (ARRA)~~Production Tax Credit (“PTC”)) have continued to increase many projects’ cost~~-~~-effectiveness, contributing to their eventual completion. Progress in the siting and permitting of projects has also supported PG&E’s sustained high success ~~rates~~rate. As described in more detail in Section ~~5~~ 3, PG&E believes the renewable development market has stabilized for the near-term and ~~that the evolution of~~ the renewable project financing sector will continue to evolve well into the future.

Notwithstanding these positive trends, the timely development of renewable energy ~~generation~~ facilities remains subject to many uncertainties and risks, including regulatory and legal uncertainties, permitting and siting issues, ~~access to financing,~~ technology viability, adequate fuel supply, and the construction of sufficient transmission capacity. ~~While PG&E intends to actively pursue the procurement of new, incremental renewable generation through competitive solicitations, its ability to build and maintain an adequate supply of renewable generation to meet and sustain the 33% RPS requirement will be highly dependent on how these market and development uncertainties and risks play out.~~ These challenges and risks are described in more detail in Sections 5 and 6.

For purposes of calculating its demand for RPS-eligible products through the modeling described in Section 6, PG&E does not assume that expiring RPS-eligible contracts in its existing portfolio are re-contracted,[17] ~~;~~ although these resources are encouraged to bid into PG&E's future competitive solicitations ~~as noted in Section 12.~~.

### 3.2.2 Impact of Green Tariff Shared Renewables Program

In 2013, SB 43 enacted the GTSR Program that allows PG&E customers to meet up to 100% of their energy usage with generation from eligible renewable energy resources. On January 29, 2015, the Commission adopted D.15-01-051 implementing a GTSR framework, approving the IOUs' applications, and requiring the IOUs to begin procurement for the GTSR Program in advance of customer enrollment.

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[17] Although the physical net short calculations in PG&E's deterministic model do not include any assumptions related to the re-contracting of expiring RPS-eligible contracts, the stochastic model can ~~choose to~~ re-contract volumes ~~in order~~ to meet procurement need~~, for~~. Such re-contracting amounts are illustrative ~~purposes~~ only and not prescriptive. PG&E's deterministic and stochastic models are described in more detail below in Section 6.

Pursuant to D.15-01-051, PG&E has submitted several advice letters related to implementation of the GTSR program that are currently pending before the Commission. In February, PG&E filed an advice letter containing its plans for advance procurement for the GTSR Program and identifying the eligible census tracts for environmental justice projects in its service territories.[18] In May, together with Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E), PG&E submitted a Joint Procurement Implementation Advice Letter (JPIAL), addressing each utility's plans for ongoing GTSR Program procurement and RPS resource and renewable energy credit (REC) separation and tracking.[19] Concurrently, PG&E filed a Marketing Implementation Advice Letter (MIAL)[20] and a Customer-Side Implementation Advice Letter (CSIAL)[21] with details regarding implementation. In addition, to accommodate GTSR procurement, PG&E filed Advice Letter 4605-E to change its RAM 6 PPAs and Request for Offer ("RFO") instructions, consistent with the minimum goals for 2015 identified in D.15-01-051.[22]

The GTSR program will impact PG&E's RPS position in two ways: (1) PG&E's RPS supply may be affected; and (2) PG&E's retail sales will be reduced corresponding to program participation. The GTSR decision permits the IOUs to supply Green Tariff customers from an interim pool of existing RPS resources until new dedicated Green Tariff projects come online. Generation from these interim facilities would no longer be counted toward PG&E's RPS targets, which will result in PG&E's RPS supply decreasing. However, there is also a possibility that RPS supply might increase in the future if generation from Green Tariff dedicated projects exceeds the demand of Green

18 PG&E Advice Letter 4593-E (supplemented March 25, 2015).

19 Advice Letter 4637-E.

20 Advice Letter 4638-E.

21 Advice Letter 4639-E.

22 *See* D.15-01-051, Section 4.2.4, pp. 25-28.

Tariff customers. PG&E will implement tracking and reporting protocols for tracking RECs transferred to and from the RPS portfolio and Green Tariff programs. Because the GTSR implementation Advice Letters discussed above[23] have not yet been approved, PG&E's RNS calculation submitted with this RPS Plan does not reflect the impact of GTSR on PG&E's RPS position. Due to the relatively small volumes of the GTSR interim pool compared to PG&E's overall RNS position, PG&E believes that its forecasts of meeting the second and third compliance period RPS targets as well as its incremental need year under either a 33% or 40% RPS would remain the same once these small GTSR volumes are incorporated. PG&E will update future RNS calculations to reflect GTSR program impacts after the advice letters implementing the program are approved.

### ~~3.2.2~~3.2.3 RPS Market Trends and Lessons Learned

As PG&E's renewable portfolio has expanded to meet the RPS goals, PG&E's procurement strategy has evolved. ~~While~~ PG&E's strategy continues to focus on the three key goals of: (1) reaching, and sustaining, the 33% RPS target~~,~~; (2) minimizing customer cost within an acceptable level of risk~~,~~; and (3) ensuring it maintains an adequate Bank of surplus RPS volumes to manage annual load and generation uncertainty. However, PG&E is continually adapting its strategy to accommodate new emerging trends in the California renewable energy market and regulatory landscape.

The California renewable energy market has developed and evolved significantly over the past few years. The market now offers a variety of technologies at generally lower prices than seen in earlier years of the RPS ~~program~~Program. The share of these technologies in PG&E's portfolio is changing as a result. For some technologies, such as solar PV, prices have dropped significantly due to various factors including technological breakthroughs, government incentives, and improving economies of scale as more projects come online.

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23 Advice Letters 4637-E, 4638-E and 4639-E.

~~As the renewable energy market has evolved, sellers are increasingly able to offer project bids that accommodate PG&E's portfolio needs. For example, even though PG&E's incremental need for RPS deliveries is not until 2020 and later, sellers have demonstrated a willingness to begin commercial operation prior to delivering to PG&E, through direct market sales or to third-party off-takers in order to capture expiring federal tax credits. These structures increase the viability of projects, and therefore the certainty of deliveries to PG&E in the future, and can reduce the overall cost of PG&E's RPS portfolio to customers by allowing developers to take advantage of the tax credits that are set to expire by 2016. In addition, PG&E has already received RPS-eligible offers with storage included, and these offers are likely to continue. Potentially valuable new products like this—that could satisfy both storage targets and mitigate integration challenges—are facilitated by solicitation flexibility. In general, an RPS Form PPA and RPS Protocol that can be modified to be responsive to a dynamic and constantly evolving market and regulatory framework will allow PG&E to meet its regulatory targets most efficiently.~~

Another trend driven by growth of renewable resources in the California Independent System Operator ("CAISO") system is the downward movement of mid-day market prices. Many renewable energy project types have little to no variable costs and therefore additions tend to move market clearing prices down the dispatch stack. This has led to a change in the energy values associated with RPS offers, with decreasing value of renewable projects that generate during mid-day hours.

The growth of renewable resources has also produced operational challenges, such as overgeneration situations and negative market prices. Provisions ~~which allow~~that provide PG&E with greater flexibility to economically bid RPS-eligible resources into the CAISO markets ~~will also become more~~ are critical to ~~help~~helping address overgeneration and negative pricing situations that are likely to ~~become more common~~increase in frequency in the future~~ on the CAISO grid~~. These provisions have both operational and customer benefits. From an operational perspective, this flexibility allows PG&E to offer its ~~renewable~~RPS-eligible resources into the CAISO's economic dispatch, which can reduce the potential for overgeneration conditions and facilitate reliable operation of the electrical grid. In addition, economic bidding ~~ensures that~~enables RPS-eligible resource generation ~~is reduced in situations involving~~to be curtailed during negative ~~prices~~pricing intervals when it is economic to do so, which ~~would increase customer~~protects customers from higher costs. Economic curtailment is discussed in greater detail in Section 11.

> ~~Moreover, changing market and policy conditions underscore the need for flexibility in the Solicitation schedule for IOUs. Such flexibility ensures PG&E has adequate time for careful review and analysis of bids and engagement with the Procurement Review Group (PRG). In opening comments filed on May 7, 2014 in response to the Staff Proposal for RPS Procurement Reform, PG&E proposed that any deadline to submit a shortlist advice letter be set no earlier than 120 days following the close of the bidding in the solicitation (Section 2 provides an overview of Procurement Reform).~~[24]

### 3.3 Demand

PG&E's demand for RPS-eligible resources is a function of multiple complex factors including regulatory requirements and portfolio considerations. ~~The Commission issued D.11-12-052, to define three statutory portfolio content categories of RPS-eligible products that retail sellers may use for RPS compliance. Additional compliance~~ Compliance rules for the RPS Program were established in D.12-06-038. In addition,

[24] ~~Pacific Gas and Electric Company's Opening Comments on April 2014 Staff Proposal for RPS Procurement Reform, filed on May 7, 2014 in R.11-05-005, p. 9 (available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M090/K936/90936699.PDF).~~

the Commission issued D.11-12-052, to define three statutory PCCs of RPS-eligible products that retail sellers may use for RPS compliance, which impacts PG&E's demand for different types of RPS-eligible products. Finally, PG&E's demand is a function of the risk factors discussed in more detail in Section 6~~. Uncertainty~~; in particular, uncertainty around bundled retail sales can have a major impact on PG&E's demand for RPS resources, as further detailed below.

#### ~~3.3.1 Demand – Procuring Resources That Satisfy the Three Portfolio Content Categories~~

~~Section 399.16 of the California Public Utilities Code, as implemented by D.11-12-052, establishes three portfolio content categories for RPS-eligible products and establishes minimum and maximum procurement limits for Category 1 and Category 3 products, respectively. Category 1 products may be generally thought of as energy and RECs that are delivered in real-time to a California Balancing Authority (CBA). Category 2 products are generally those generated outside of California and that are firmed and shaped with substitute energy so that energy deliveries may occur at a different time than the RPS generation. Category 3 products may generally be thought of as unbundled RECs.~~

~~PG&E's 2014 RPS Solicitation Protocol seeks offers meeting any of the three portfolio content categories within the statutory limitations for each category, with a focus on long-term contracts, because of both incremental need to sustain 33% beyond 2020 and the desire to purchase products that are bankable[25] and therefore offer flexibility in compliance use to optimize PG&E's RPS portfolio over time. PG&E is~~

~~[25] Non-grandfathered, short-term contracts (i.e., those of less than 10 years in duration) are deducted from any excess procurement in a given compliance period. *See* Cal. Pub. Util. Code § 399.13(a)(4)(B).~~

~~only interested in bankable RPS procurement that will help to meet RPS compliance requirements in 2020 and beyond.~~

~~PG&E plans to continue evaluating the cost-effectiveness of long-term contracts for Category 3[26] products with deliveries beginning both in the near and longer term depending on the market's pricing signals. Category 3 products are a limited, but important part of PG&E's procurement strategy. All RECs are fungible and have the same underlying RPS value, and as such, Category 3 products may provide a very low-cost compliance option for PG&E's customers. Category 3 deals may also provide opportunities to mitigate integration and other operational challenges associated with incremental procurement from typical Category 1 or Category 2 procurement. PG&E notes that Category 2 and 3 products may reduce integration and other operational challenges associated with typical Category 1 procurement.[27]~~

### 3.3.1 ~~Demand –~~ Near-Term Need for RPS Resources

Because PG&E has no incremental procurement need through [redacted] under a 33% RPS requirement and through [redacted] under a 40% RPS scenario, PG&E proposes to not hold an RPS solicitation in 2015. As discussed in the summary of key issues, PG&E has sufficient time in the coming years to respond to changing market, load forecast, or regulatory conditions and will reassess the need for future RFOs in next

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~~[26] Pursuant to D.11-12-052, PG&E may not credit toward RPS compliance any Category 3 products that exceed 25% of Incremental Procurement in the first compliance period, decreasing to 15% of Incremental Procurement in the second compliance period, and finally decreasing to 10% of Incremental Procurement in the third compliance period and thereafter.~~

~~[27] SB 2 (1x) places restrictions on the sum of Category 2 and Category 3 products that PG&E may credit toward compliance during each compliance period (with additional maximum restrictions described in the preceding footnote). This sum may not exceed 50% of PG&E's Incremental Procurement in the first compliance period. The allowed sum decreases to 35% of PG&E's Incremental Procurement in the second compliance period and decreases further to 25% of Incremental Procurement in the third compliance period and thereafter.~~

year's RPS Plan. Although many factors could change PG&E's RPS compliance position, PG&E believes that its existing portfolio of executed RPS-eligible contracts, its owned RPS-eligible generation, and its expected Bank balances will be adequate to ensure compliance with near-term RPS requirements. Additionally, PG&E expects to procure additional volumes of incremental RPS-eligible contracts in 2016 through mandated procurement programs, such as the RAM, ReMAT, and BioMAT Programs.

### 3.3.2 Portfolio Considerations

~~After three consecutive years of relatively flat sales,~~One of the most important portfolio considerations for PG&E is the forecast of bundled load. PG&E's most recent Load Forecast, which is used in this RPS Plan, is an April 2015 updated version of the Alternate Scenario Forecast used in the 2014 Bundled Procurement Plan ("BPP") submitted in October 2014 in R.13-12-010. PG&E ~~is~~updates the bundled load forecasts annually to reflect any new events and to capture actual load changes. It is important to emphasize that PG&E's Alternative Scenario is a forecast that includes a number of assumptions regarding events which may or may not occur.

PG&E is currently projecting a decrease in retail sales in ~~2014~~2015 and a continued retail sales decrease through 2024, followed by modest growth ~~in 2015~~ [redacted] thereafter. These changes are driven by the increasing impacts of ~~conservation, energy efficiency, direct access and community choice aggregation~~Energy Efficiency ("EE"), customer-sited generation, and Direct Access ("DA") and CCA participation levels, and ~~customer-side generation, and are moderated~~are offset slightly by an improving economy and growing electrification of the transportation sector. As described in more detail in Section 6.2.1, PG&E uses its stochastic model to simulate a range of potential retail sales forecasts.

In addition to retail sales forecasts, as discussed in Sections 6, 7, and 8, PG&E's long-term demand for new RPS-eligible project deliveries is driven by: (1) PG&E's current projection of the success rate for its existing RPS portfolio, ~~as calculated in PG&E's deterministic model (as further discussed in Section 6 and 7),~~ which PG&E

uses to establish ~~in its procurement activities~~ a minimum margin of procurement ~~(as further discussed in Section 7);~~; and (2)~~-~~ the need to account for its risk~~-~~-adjusted need, including any Voluntary Margin of Procurement ("VMOP") as determined by PG&E's stochastic model ~~(as further described in Section 6 and 7).~~. The risk and uncertainties that justify the need for VMOP are further detailed and quantified in Sections 6 and 7.

~~Finally, PG&E has proposed a GTSR program, which, if approved by the Commission as part of the implementation of SB 43 (see RPS Plan Introduction), would use some relatively small volumes from PG&E's existing portfolio of RPS projects to serve GTSR demand until specific resources purchased on behalf of the GTSR are online. PG&E will update its RNS when the GTSR application is approved and resources are dedicated to the GTSR Program. This may slightly decrease the size of PG&E's projected RPS Bank or increase slightly PG&E's long-term RPS net short position.~~

### 3.4 Anticipated Renewable Energy Technologies and Alignment of Portfolio With Expected Load Curves and Durations

PG&E's procurement evaluation methodology considers both market ~~forces~~value and the portfolio fit of RPS-eligible resources in order to determine PG&E's optimal renewables product mix. With the exception of specific Commission-mandated programs such as the RAM, ReMAT, and BioMAT Programs, PG&E does not identify specific renewable energy technologies or ~~energy products~~product types (e.g., baseload, peaking as-available, or non-peaking as-available) that it is seeking to align, or fit, with specific needs in its portfolio. Instead, PG&E identifies an RPS-eligible energy need in order to fill an aggregate open position identified in its planning horizon~~,~~ and ~~then applies a PAV methodology~~selects project offers that ~~incorporates~~are best positioned to meet PG&E's current portfolio needs~~, in order to ensure~~. This is evaluated through the use of PG&E's Portfolio Adjusted Value ("PAV") methodology, which ensures that the ~~energy products and~~ procured renewable energy ~~technologies~~products provide the best fit for PG&E's portfolio at the least cost.[28] ~~However, in order to ensure that PG&E's PAV methodology effectively captures portfolio need~~ Starting in the 2014 RPS RFO, PG&E ~~needs to be able to include an~~began utilizing the interim integration cost adder to accurately capture the ~~value to~~impact of intermittent resources on PG&E's portfolio. When this adder is finalized by the Commission, PG&E's Net Market Value ("NMV") methodology will be updated to use the values and methodologies of the final integration cost adder. PG&E's PAV and NMV methodologies were described in detail in PG&E's 2014 RPS Solicitation Protocol.[29]

### 3.5 RPS Portfolio Diversity

PG&E's RPS portfolio contains a diverse set of technologies, including solar PV, solar thermal, wind, small hydro, bioenergy, and geothermal projects in a variety of geographies, both in-state and out-of-state. PG&E's procurement strategy addresses technology and geographic diversity on a quantitative and qualitative basis.

In the NMV valuation process, PG&E models the location-specific marginal energy and capacity values of a resource based on its forecasted generation profile. Thus, if a given technology or geography becomes "saturated" in the market, then those projects will see declining energy and capacity values in their NMV. This aspect of PG&E's valuation methodology should result in PG&E procuring a diverse resource mix if technological or geographic area concentration is strong enough to change the relative value of different resource types or areas. In addition, technology and geographic diversity have the potential to reduce integration challenges. PG&E's use of the integration cost adder in its NMV valuation process may also result in procurement of different technology types.

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~~28 A more detailed description of the LCBF methodology, including the PAV considerations, is provided in Attachment K to PG&E's 2014 RPS Solicitation Protocol, which may be found in Appendix H.~~

29 *See* PG&E, 2014 RPS Solicitation Protocol, pp. 24-28 (available at http://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/RPS2014/RPS_Solicitation_Protocol_01052015.pdf).

Diversity is also considered qualitatively when making procurement decisions. Resource diversity may decrease risk to PG&E's RPS portfolio given uncertainty in future hourly and locational market prices as well as technology-specific development risks.

PG&E recognizes that resource diversity is one option to minimize the overgeneration and integration costs associated with technological or geographic concentration. In general, PG&E believes that less restrictive procurement structures provide the best opportunity to maximize value for its customers, allowing proper response to changing market conditions and more competition between resources, while geographic or technology-specific mandates add additional costs to RPS procurement. PG&E's current quantitative and qualitative approach to resource diversity would remain the same under a 40% RPS scenario as the existing approach described above.

**~~3.5~~3.6 Optimizing Cost, Value, and Risk for the Ratepayer**

From 2003~~-~~ to 2012, PG&E's annual RPS-eligible procurement and generation costs from its existing contracts and utility-owned portfolio grew at a relatively modest pace. However, the costs of the RPS program are becoming more apparent on customer bills and will increase as RPS projects come online in significant quantities. Over the period of two years (2013 and 2014), the renewable generation in PG&E's portfolio ~~is expected to increase~~increased by approximately the same amount ~~or more than~~that it grew over the entire prior history of the RPS Program (2003~~–~~–2012). In addition to cost impacts resulting from the direct procurement of renewable resources, customer costs are also impacted by the associated indirect incremental transmission and integration costs.

~~In addition to cost impacts resulting from the direct procurement of the renewable resource, customer costs are also impacted by the associated incremental transmission and integration costs.~~ PG&E is ~~well~~ aware of these direct and indirect cost impacts and will attempt to mitigate them whenever possible, particularly when entering into incremental long-term commitments. PG&E's fundamental strategy for mitigating RPS cost impacts is to balance the opposing objectives of: (1) delaying additional RPS-related costs until deliveries are needed to meet a physical compliance requirement; and (2)~~-~~ managing the risk of being caught in a "seller's market," where PG&E faces potentially high market prices in order to meet near-term compliance deadlines. When these objectives are combined with the general need to manage overall RPS portfolio volatility based on demand and generation uncertainty, PG&E believes it is prudent and necessary to ~~build and~~ maintain an adequate Bank through the most cost-effective means available~~ an adequate Bank.~~ .

In addition, PG&E seeks to minimize the overall cost impact of renewables over time through ~~(1)~~ promoting competitive processes that can encourage price discipline, ~~(2)~~and using the Bank to help limit long-term over-procurement~~ that could place volumetric pressure on the total dollar impact from renewables, and (3) considering opportunistic procurement of unusually attractive near-term offers (4) balancing the cost of adjusting the size of the Bank with the cost impact of long-term over-procurement.~~

~~Based on this RPS need, PG&E evaluates the PAV of offers during the procurement phase to ensure that incremental procurement is LCBF. A more detailed description of the LCBF methodology, including the PAV considerations, is provided in Attachment K to PG&E's 2014 RPS Solicitation Protocol, which may be found in Appendix H.~~

. PG&E generally supports the use of competitive procurement mechanisms that are open to all RPS-eligible technologies and project sizes. ~~As~~ As described in greater detail in Section 13.3, as PG&E makes progress ~~to~~toward achieving the 33% RPS ~~goal of 33%,~~ target, it expects that the ~~impact~~cost impacts of mandated procurement programs ~~focused~~that focus on particular technologies or project ~~sizes~~~~[30]~~ ~~will be more significant as they become a larger share of PG&E's incremental procurement, as described in greater detail in Section 11. PG&E expects that these programs may therefore~~size may increase the overall costs of PG&E's RPS portfolio for customers~~, which~~ as procurement from these programs comprise a larger share of PG&E's incremental procurement goals. This further underscores the need to implement an RPS cost containment mechanism that provides a ~~real~~ cap on costs. PG&E supports a technology~~-~~-neutral procurement process, in which all technologies can compete to offer the best value to customers at the lowest cost.

### ~~3.6~~3.7 ~~PG&E's 2014~~ Long-Term RPS Optimization Strategy

PG&E's long-term optimization strategy seeks to both achieve and maintain RPS compliance through and beyond 2020 and to minimize customer cost within an acceptable level of risk. PG&E's optimization strategy ~~has evolved~~continues to evolve as its RPS compliance position through 2020 ~~has improved. As such,~~and beyond continues to improve. Although PG&E ~~is moving into a new phase in the RPS program, from a~~remains mindful of meeting near-term ~~focus on reaching initial~~ compliance targets ~~to a long-term (post-2020) focus on~~, it also seeks to refine strategies for maintaining compliance~~.~~ in a least-cost manner in the long-term (post-2020). PG&E's optimization strategy includes an assessment of compliance risks and approaches to protect against such risks by maintaining a Bank that is both prudent and needed to manage a 33% RPS operating portfolio after 2020. PG&E employs two- models in order to optimize cost, value, and risk for the ratepayer while achieving sustained RPS compliance. This optimization analysis results in PG&E's "stochastically-optimized net short" ~~(~~("SONS~~),~~"), which PG&E uses to guide its procurement strategy, as further described in Sections 6 and 7.

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~~[30] Examples include the Renewable Market Adjusting Tariff (ReMAT) (Senate Bill 32), and the Bioenergy FIT (SB 1122).~~

PG&E's long-term optimization strategy includes three primary components: (1) incremental procurement~~,~~; (2) possible sales of ~~excess banked~~surplus procurement~~,~~; and (3) effective use of the Bank. ~~PG&E's identified~~Although PG&E proposes not to hold a 2015 RPS ~~need and 2014 RPS~~ solicitation, future incremental procurement ~~goal is described~~to avoid the need to procure extremely large volumes in ~~greater detail in Section 6 and 7.~~any single year remains a central component of PG&E's long-term RPS optimization strategy. In addition to procurement, PG&E's optimization strategy includes consideration of sales of ~~excess banked~~surplus procurement that provide a value to~~-~~ customers. [redacted]

The third component of the optimization strategy is effective use of the Bank. ~~PG&E's~~ Under the existing 33% RPS target and current ~~optimization strategy projects the use of~~market assumptions, PG&E plans to apply a portion of its projected Bank to meet compliance requirements beginning in [redacted]. Additionally, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in PG&E's stochastic model, while maintaining a minimum Bank size of at least [redacted].

Under a 40% RPS by 2024 scenario, the components of PG&E's ~~projected Bank as a VMOP~~ [redacted]

[redacted]~~.~~[31] optimization strategy would remain the same. However, under the 40% RPS scenario and current market assumptions, PG&E would plan to maintain a minimum Bank size of at least [redacted]. See Section 7 for additional information regarding the use and size of PG&E's Bank.

### ~~3.6.1 PG&E's 2014 Procurement Goal to Minimize Cost While Maintaining an Acceptable Level of Non-Compliance Risk~~

~~PG&E's optimization process results in PG&E's 2014 RPS Solicitation procurement target of between zero and 1,600 GWh~~[32] ~~per year of RPS-eligible products providing compliance value in 2020 and onwards. PG&E is seeking offers for resources with deliveries beginning in 2020 or later.~~

~~It is worth emphasizing that PG&E's identified RPS need and 2014 RPS solicitation procurement goal is, however, constantly evolving to reflect both our procurement achievements and changing market conditions and is dependent on many extremely dynamic factors, as detailed in Section 6.~~

## 4 Project Development Status Update

### ~~4.1 Project Development Status Update~~

~~A written status report in the form of~~In Appendix B ~~addresses the ACR's requirement that~~, PG&E ~~provide~~provides an update on the development of RPS-~~eligible~~eligible ~~renewable energy~~ resources currently under contract but not yet delivering

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[31] [redacted]

~~[32] As described in Section 5, this number incorporates an estimated level of project failure associated with the incremental procurement. Thus, while PG&E intends to execute contracts for deliveries of between zero and 1,600 GWh per year, PG&E's actual GWh need resulting from the optimization process is lower than 1,600 GWh.~~

~~generation.[33]~~energy. The table in Appendix B updates key project development status indicators provided by counterparties and is current as of ~~May 6, 2014~~June 17, 2015.[34] These key project development status indicators help PG&E to determine if ~~the~~a project will meet its contractual milestones and identify impacts on PG&E's renewable procurement position and procurement decisions.

#### ~~4.1.1 Portfolio-Wide Development Summary~~

Within PG&E's active portfolio,[35] there are ~~106~~ 107 RPS-eligible projects that were executed ~~post-~~after 2002~~ and which led to incremental RPS procurement. Sixty-one~~. Seventy-six of these contracts have achieved full commercial operation and started the delivery term under their PPAs~~ with PG&E. Forty-five~~. Thirty-one contracts have not ~~achieved full commercial operation~~started the delivery term under their PPAs~~ with PG&E~~. Of the ~~forty-five~~31 contracts that have not ~~achieved full commercial operation~~started the delivery term under their PPAs with PG&E~~, one geothermal project and five PV projects are phased projects that are not~~: 18 have not yet ~~delivering their full capacity, but are currently delivering energy from early phases of the projects. Including the phased projects, fifteen projects are under~~started construction~~. The remaining projects are either under development but not yet under~~;

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~~33 ACR at 10.~~

34 ~~The table in~~ Appendix B includes PPAs procured through the RAM and PV Programs, but does not include small renewable FIT PPAs. PG&E currently has ~~87~~72 executed Assembly Bill ("AB") 1969 PPAs in its portfolio and ~~15~~29 ReMAT PPAs, totaling ~~108.31~~104 MW of capacity. These small renewable FIT projects are in various stages of development, with ~~49~~60 already delivering to PG&E under an AB 1969 PPA and ~~one~~11 delivering to PG&E under a ReMAT PPA. Information on these programs is available at http://www.pge.com/feedintariffs/.

35 ~~Active~~ PG&E's active portfolio includes RPS-eligible projects that were executed (but not terminated or expired) and CPUC~~-~~-approved as of ~~May 6, 2014~~June 17, 2015, not including amended post~~-~~-2002 QF contracts, contracts for the sale of bundled renewable energy and green attributes by PG&E to third parties, Utility-Owned Generation ("UOG") projects, or ~~feed-in-tariff~~ FIT projects.

five have started construction~~, or are complete~~ but are not yet online; and eight are delivering energy, but have not ~~achieved full commercial operation~~yet started the delivery term under their PPAs~~ with PG&E.~~

. Based on historic experience, projects that have commenced construction are generally more viable than projects in the pre-construction phase, although PG&E expects most of the pre~~-~~-construction projects currently in its portfolio to achieve commercial operation under their PPA.

## 5 Potential Compliance Delays

~~PG&E continues to be committed to meeting the State's ambitious renewable energy goals, and to the success of California's 33% RPS Program. Nonetheless, in order to provide the Commission and the public with a comprehensive perspective of its renewable procurement and compliance strategy, PG&E recognizes the many uncertainties and risks inherent in the development of renewable energy generation facilities.~~

Through the considerable experience it has gained over the past decade of RPS procurement, PG&E ~~has familiarity~~is familiar with the~~ recurring~~ obstacles confronting renewable energy developers. These include ~~the permitting and siting of projects,~~ securing financing, ~~mitigating technology risks, securing reliable and economic fuel supplies~~siting and permitting projects, expanding transmission capacity, and interconnecting projects to the grid. At both the federal and state levels, new programs and measures continue to be implemented to address these issues. However, even with these efforts, ~~significant~~ challenges remain ~~which~~that could ultimately ~~delay~~impact PG&E's ability to meet California's RPS goals. Moreover, operational issues, such as curtailment, may impact PG&E's RPS compliance. This section describes the most significant RPS compliance risks and some of the steps PG&E is taking to mitigate~~ ~~ them.[36]

### 5.1 Project Financing

~~As demonstrated by higher project success rates, the~~ The financing environment for ~~renewable~~solar PV and wind projects ~~currently provides~~ continues to be healthy, with access to low-cost capital and ~~federal tax incentives, and~~a variety of ownership structures for project developers. However, for renewable ~~resources~~technologies that are ~~unproven~~less proven, less viable, or reflect a higher risk profile, the financing environment is more constrained, with ~~few~~higher costs of capital and fewer participants willing to lend or invest ~~in such projects~~.

Federal and state incentives such as the PTC and ITC continue to fuel renewable growth in California. ~~Although~~In 2015, the Internal Revenue Service extended the applicable dates for the “beginning of construction” guidance for PTC-eligible facilities to January 1, 2015, and the “placed in service” date to January 1, 2017.[37] This allows the PTC or ITC tax benefits ~~of the 1603 Cash Grant program have wound down for the most part, renewable project sponsors continue to rely on the ITC~~

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[36] This section is not intended to provide a detailed justification for an enforcement waiver or a reduction in the portfolio content requirements pursuant to ~~California Public Utilities Code~~ Sections 399.15(b)(5) or 399.16(e). To the extent that PG&E finds that it must seek such a waiver or portfolio balance reduction in the future, it reserves the right to set forth a more complete statement, based upon the facts as they appear in the future, in the form of a petition or as an affirmative defense to any action by the Commission to enforce the RPS compliance requirements. ~~Dynamic external factors may change PG&E’s assessment over time of its ability to comply with the RPS compliance requirements.~~

[37] Notice 2015-25 allows a taxpayer to claim a PTC under Section 45 of the Internal Revenue Code (“IRC”), or a 30% ITC under Section 48 (ITC) in lieu of the PTC, for eligible facilities such as wind, geothermal, biomass, marine, landfill gas, and hydro, if the facility began construction before January 1, 2015 or was placed in service by January 1, 2017.

~~and PTC to make projects cost effective.[38] The 5~~for non-solar facilities to continue well beyond 2014. Solar energy facilities continue to be eligible for a 30% ITC if they are placed in service by December 31, 2016.[39] The five-year and ~~7~~seven-year Modified Accelerated Cost Recovery System ("MACRS") allows for accelerated tax depreciation ~~is also available for renewable facilities placed in service in 2014 and beyond. In general, federal and state~~deductions to renewable tangible property.[40] These tax incentives and the MACRS depreciation deductions enable businesses to reduce their tax liability and accelerate the rate of return on renewable investments. They also provide a workable framework for projects to negotiate financing. As a result, tax incentives have spurred significant investment in renewable energy and generally amount to between 35 ~~to~~and 60 cents per dollar ("¢/$") of capital cost.

Tax equity remains a core financing tool for renewable developments, and ~~emerging~~ ownership structures such as Master Limited Partnerships and Yield Cos are also being ~~considered~~utilized as project sponsors market and investors competitively shop for solar and wind investments ~~in California.~~

~~PTC and ITC rules for non-solar renewables (wind, biomass, geothermal, landfill gas, municipal solid waste, hydropower, and marine/hydrokinetic) require qualified facilities to have "begun construction" by the end of 2013. This new Internal Revenue Service (IRS) rule potentially allows the non-solar PTC and~~

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~~38 Section 45 of the Internal Revenue Code allows a PTC based on the sale of electricity over a 10-year period generated by certain renewable energy projects, such as wind, biomass, geothermal, landfill gas and municipal solid waste. Section 48 of the Internal Revenue Code allows for a tax credit equal to 30% of project's qualifying costs for certain types of commercial energy projects, including solar, geothermal, fuel cells, and small wind projects. The tax credit is realized in the year that the project is placed in service.~~

39 Section 48 of the IRC allows for a tax credit equal to 30% of project's qualifying costs for certain types of commercial energy projects, including solar, geothermal, fuel cells, and small wind projects, and a 10% tax credit for geothermal, micro turbines and combined heat and power. The tax credit is realized in the year that the project is placed in service.

40 MACRS provides for a five-year tax cost recovery period for renewable solar, wind, geothermal, fuel cells and combined heat and power tangible property. Certain biomass property is eligible for a seven-year tax cost recovery period under MACRS.

~~ITC~~. These structures allow developers who cannot use tax benefits ~~to continue well beyond 2013.[41] Solar energy facilities continue to be eligible for a 30% ITC if they are placed in service by December 31, 2016, and are not impacted by the ITC or PTC provisions of American Taxpayer Relief Act (ATRA).[42]~~

efficiently to barter the benefits to large corporations or investors in exchange for cash infusions for their projects. At this time, tax incentive structures after 2016 are unknown. The PTC and 30% ITC incentives end in 2016. Unless the tax code is modified or extended, the renewable energy ITC will drop to 10% after December 31, 2016. However, there are efforts underway to extend or modify the PTC and ITC.[43] Despite the uncertainty surrounding renewable energy project tax incentives, PG&E believes ~~that~~ there are indications that ~~the~~ healthy trends for renewable project financing will continue~~, although uncertainty and obstacles remain. Notwithstanding these developments, the tax incentive structures after 2016 are not yet known. And while confidence in an extended tax incentive structure may presently exist among market analysts, PG&E's identified need for additional volumes of RPS-eligible products, and~~

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[41] ~~IRS Notice 2013-29, published in April 15, 2013.~~

[42] ~~The tax credit rules for solar, fuel cells, small wind, micro turbines, CHP facilities, geothermal that generates heat, and geothermal that generates electricity, but begins construction after 2013, continue to have the same placed-in-service tests as before ATRA.~~

[43] H.R. 2412 would extend the renewable energy ITC for a period of five years for eligible renewable solar, small wind energy, fuel cell, micro turbine, thermal energy and combined heat and power system properties that begin construction before January 1, 2022.

In addition, in its proposed budget for fiscal year 2016, the Obama administration proposes to modify and permanently extend the renewable PTC and ITC. For facilities that begin construction in 2016 or later, the proposal would make the PTC permanent and refundable. Solar facilities that qualify for the ITC would be eligible to claim the PTC. The proposal would also permanently extend the ITC at the 30 percent credit level, which is currently scheduled to expire for properties placed in service after December 31, 2016, and it would make permanent the election to claim the ITC in lieu of the PTC for qualified facilities eligible for the PTC.

~~its 2014 RPS procurement goal, focuses on projects with energy deliveries to PG&E commencing after the PTC and ITC expire.~~[44].

### 5.2 Siting and Permitting ~~of Renewable Generation Facilities~~

~~PG&E continues to address the siting and permitting needs faced by renewable generators located in California through provisions in its 2014 RPS Plan and RPS Solicitation. For PG&E's position regarding the need for additional environmental data review in the Commissioner's reform to the RPS procurement process, see Section 2.12.1.3.~~

PG&E works with various stakeholder groups toward finding solutions for environmental siting and permitting issues faced by renewable energy development. For example, PG&E works collaboratively with environmental groups, renewable energy developers and other stakeholders to ~~develop~~encourage sound policies through ~~the California Desert~~a Renewable Energy Working Group, an informal and diverse group working to protect ecosystems, landscapes and species, while supporting the timely development of energy resources in the California desert~~. Jointly with this group, PG&E submitted a recommendation to the United States Department of Interior on the Solar Programmatic Environmental Impact Statement for improving~~ and ~~streamlining the Bureau of Land Management's processing of solar energy applications in a way that avoids or minimizes harm to California's environment.~~other suitable locations. Long-term and comprehensive planning and permitting processes ~~such as the Desert Renewable Energy Conservation Plan (DRECP)~~ can help better inform and facilitate renewable development.

~~Additionally, California's Legislature passed several new bills regarding renewable project permitting and development. AB 1x 13, which was signed into law by Governor Jerry Brown in August 2011, establishes a renewable energy~~

[44] ~~The projects could still come online prior to the expiration of tax credits, initially selling the energy to other parties.~~

~~planning grant program for local jurisdictions. The bill aligns the siting and permitting of renewable energy power plants, particularly those in the Mojave and Colorado deserts, with the DRECP in an effort to streamline the review and approval of renewable energy projects in those areas by coordinating permitting for biological and natural resources impacts. In the 2012 legislative session, AB 1255[45] was signed into law, which simplifies the process established by AB 1x 13 by allowing local jurisdictions to apply for funding to revise and modify planning documents in order to facilitate renewable development in the region.~~

~~Another effort to streamline and simplify permitting and siting in California in 2013 includes the joint issuance by the federal Council on Environmental Quality and the California Governor's Office of Planning and Research of the Draft Handbook, "NEPA and CEQA: Integrating California State and Federal Environmental Reviews."[46] Completion of this handbook serves to improve the efficiency, transparency, and coordination for conducting joint National Environmental Policy Act (NEPA) and the California Environmental Quality Act (CEQA) environmental reviews.~~

PG&E is hopeful that these and other efforts will establish clear requirements that developers and other interested parties can satisfy in advance of the submission of offers to PG&E's ~~2014 and~~ future solicitations, and will, as a result, help decrease the time it takes parties to site and permit projects while ensuring environmental integrity.

Permitting challenges for projects are improving as a result of these and other efforts to streamline and adjust the permitting process for renewable energy projects. While these improvement efforts are ongoing, permitting and siting hurdles remain for renewables projects. Common issues may include challenges related to farmland designation and Williamson Act contracts, tribal and cultural resources areas, protected

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[45] ~~http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201120120AB1255.~~

[46] ~~http://opr.ca.gov/docs/NEPACEQAHandbookMarch2013.pdf.~~

species, and county-~~-~~imposed moratoriums. These hurdles may impact development schedules for projects.

### 5.3 Transmission and Interconnection ~~Reform~~

Achieving timely interconnection is an important part of the project development process. Delays in achieving interconnection can occur for various reasons, including the delay of substation construction, permitting issues, telecommunications delays, or overly aggressive timeline assumptions. While delays in interconnection can lead to delays in project development, such delays to date have not had a major impact on PG&E's ability to meet its RPS procurement targets.

Over the past few years, the CAISO and the IOUs have seen significant increases in the number of requests for grid interconnection. As the number of proposed RPS-eligible projects continues to increase in California, planning for how ~~all of~~ these projects would be connecting into the California grid has become increasingly challenging. The growth in these requests has, in turn, extended estimated project development timelines, which creates a significant barrier to financing projects endeavoring to come online within tight contractual milestone dates. Similarly, the growth in interconnection requests has made it difficult to estimate reliable interconnection study results and to identify necessary transmission build-outs.

Accordingly, PG&E has initiated a number of internal efforts~~,~~ and collaborated on external initiatives~~,~~ to address these challenges at both the transmission and distribution levels. ~~The most~~Recent notable changes in the distribution-level interconnection process ~~to date~~ included: (1) amending the Wholesale Distribution Tariff in ~~March 2011~~October 2014 to address modifications similar to those made to the CAISO's Tariff ~~in December 2010 to handle higher volumes of interconnection requests~~; and (2) amending Rule 21 in ~~September 2012 to include a process and agreements for RPS-eligible generators to provide an interconnection path for exporting generators that ultimately enter into a Public Utility Regulatory Policies Act PPA with PG&E.~~ January 2015 to capture the technological advances offered by smart inverters.

Additionally, over the past few years, PG&E has worked with the CAISO and industry stakeholders in ongoing stakeholder initiatives enhancing the transmission-level interconnection processes. Most significant among the changes has been the Generator Interconnection and Deliverability Allocation Procedures, ~~formally known as Transmission Planning Process Generation Interconnection Procedures Integration,~~ which has streamlined the process for identifying ~~ratepayer~~customer-funded transmission additions and upgrades under a single comprehensive process ~~and~~. This initiative also provides incentives for renewable energy developers to interconnect to the CAISO grid at the most cost-effective locations. PG&E has also actively contributed to the CAISO's Interconnection Process Enhancements stakeholder initiative that seeks to continuously review potential enhancements to the generator interconnection procedures.

Finally, at the intersection of transmission-level and distribution-level interconnections, is the ~~Resource Adequacy Deliverability for~~ Distributed Generation ~~(RADDG) program.~~Deliverability ("DGD") process. In 2013, PG&E collaborated extensively with the CAISO to implement the first annual cycle ~~of RADDG~~, and the second ~~cycle was~~and third cycles were successfully completed in 2014~~.~~ and 2015, respectively. Under the ~~RADDG program~~DGD Program, the CAISO conducts an annual study to identify ~~megawatt~~MW amounts of available deliverability at transmission nodes on the CAISO~~-~~-controlled grid. Based on the deliverability assessment results, distributed generation facilities that are located or seeking interconnection at nodes with identified available deliverability may apply to the appropriate Participating Transmission Owner ~~(~~("PTO~~)~~") to receive an assignment of deliverability for Resource Adequacy ("RA") counting purposes.

~~Early RPS Solicitations had no requirement for Sellers to have applied for or received an interconnection study. In order to ensure that PG&E has more accurate information as to the interconnection costs and upgrades required, PG&E's 2013 RPS Solicitation has required that Sellers have at least the~~

~~equivalent of a Phase II Interconnection Study from the CAISO. All projects in Cluster 5 and earlier had completed Phase II studies before the 2013 RPS Solicitation bids were due in early 2014, and were therefore eligible to submit bids. PG&E will continue to accept both energy-only and fully deliverable offers, and will include applicable resource adequacy value in the valuation process.~~

### 5.4 ~~Procurement Expenditure Limitations for the RPS Program~~Curtailment of RPS Generating Resources

As discussed in more detail in Section 11, if RPS curtailed volumes increase substantially due to CAISO market or reliability conditions, curtailment may present an RPS compliance challenge. In order to better address this challenge, PG&E's stochastic model incorporates estimated levels of curtailment, which enables PG&E to plan for appropriate levels of RPS procurement to meet RPS compliance even when volumes are curtailed. Additional detail on these assumptions is provided in Section 6.2.

~~5.4~~

~~As discussed throughout this Plan, PG&E is making progress towards meeting California's RPS procurement mandates. Nevertheless, PG&E recognizes that these mandates have a significant and increasing cost impact on its customers.~~

~~When California's legislature passed SB 2 (1x) in 2011, it required the CPUC to develop a limitation on total RPS costs for each electrical corporation. The legislature specified that the cost limitation must prevent the 33% RPS from causing "disproportionate rate impacts."~~[47] ~~If PG&E exceeds the Commission-approved cost cap, it may refrain from entering into new RPS contracts and constructing RPS-eligible facilities unless additional procurement can be undertaken with only "de minimis" rate impacts.~~[48]

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[47] ~~Cal. Pub. Util. Code § 399.15(d)(1).~~

[48] ~~Cal. Pub. Util. Code § 399.15(f).~~

~~PG&E makes every effort to procure least-cost and best-fit renewable resources. However, recognizing the cost impact that RPS procurement will have on its customers, PG&E strongly supports the establishment of a clear, stable, and meaningful procurement expenditure limitation that both informs procurement planning and decisions, and promotes regulatory and market certainty.~~

~~SB 2 (1x) requires that the Commission waive the RPS obligations of an electrical corporation once it meets the cost containment limitation, provided that additional resources cannot be procured without exceeding a de minimis increase in rates. This may allow PG&E to stop procuring RPS-eligible electricity short of the compliance requirements set forth in D.11-12-020.~~

~~PG&E has proposed in its comments submitted in the ongoing Procurement Expenditure Limitation (PEL) proceeding that a buffer of 2% of an IOU's total generation-related costs (in the years an IOU has outstanding RPS needs) be added to an IOU's PEL, above and beyond the anticipated costs of meeting the RPS compliance targets. The PEL proposals PG&E has made in its comments, including the 2% buffer, balance the imperatives of avoiding disproportionate rate increases while achieving the state's RPS goals.~~

### ~~5.5 The 2014 Solicitation Protocol and Form PPA Seek to Minimize Potential Compliance Delays~~

~~PG&E views project failure, or delayed deliveries, as potential RPS compliance risks. To address these risks, PG&E has developed a set of evaluation guidelines and PPA provisions that attempt to safeguard against common project viability concerns. These evaluation criteria and contract terms continue to evolve from solicitation to solicitation to reflect what PG&E has learned from its portfolio of RPS contracts and the current realities of the renewable energy project development market. For the 2014 Solicitation, PG&E~~

~~has highlighted below a few of the key screening steps and contract terms to address project viability issues.~~

### ~~5.5.1 Requested Online Date~~

~~PG&E is seeking offers with deliveries in 2020 and beyond. The extended length of time between expected execution of contracts from the 2014 Solicitation and commencement of deliveries provides developers with additional time for development activities and should lower the likelihood of developers missing key milestones under the PPA.~~

### ~~5.5.2 Planned Tax Credit Expirations~~

~~PG&E has taken a number of steps to address developers' interest in bringing eligible projects online before the upcoming expiration of the ITC at the end of 2016. PG&E continues to shorten the timeframe from issuing a solicitation to final contract execution and intends to continue with this overall streamlined process. PG&E has also included a provision in the PPA that allows Sellers to sell to a third party before starting deliveries to PG&E. This provision provides Sellers with the flexibility to meet the ITC deadline, which improves the financial viability of the project, while still providing a delivery schedule that fits PG&E's need for deliveries in 2020 and beyond.~~

### ~~5.5.3 Siting and Permitting~~

~~PG&E is retaining in its 2014 RPS Form PPA a 6-month limit in allowed delays related to permitting and transmission. This reduced delay allowance was first introduced in its 2011 RPS Form PPA to mitigate siting and permitting risks, by incentivizing developers with highly viable projects to submit bids into the solicitation. The reduced delay allowance also bounds the uncertainty associated with a project's~~

~~online date, thus improving PG&E's ability to forecast the potential volume of RPS generation available for compliance.~~

~~In addition, PG&E will continue to engage in milestone monitoring activities for projects procured via the 2014 RPS Solicitation. Close monitoring of contract performance allows PG&E to determine if counterparties are on schedule with their permitting and construction activities.~~

#### ~~5.5.4 Transmission and Interconnection~~

~~PG&E requires that projects have a minimum of a Phase II Interconnection Study to bid into the 2014 Solicitation. By requiring projects to be further along in the interconnection process than in earlier solicitations (pre-2013), PG&E is better able to evaluate the potential delays and risks associated with the project's transmission and interconnection plan. Additionally, PG&E's required delivery dates in 2020 and beyond provides Sellers with longer lead times for transmission upgrades than in earlier RPS solicitations. Along with the six months of transmission delays allowed under the Form PPA, these provisions provide a reasonable safeguard against interconnection and transmission related delays. Finally, PG&E has included a new provision in the Form PPA that allows Sellers to pay liquidated damages for failure to meet their expected completion date for Full Capacity Deliverability Status (FCDS). Depending on the results of the project's Phase II study, the expected FCDS date could be beyond the Initial Energy Delivery Date (IEDD) and in turn, PG&E will value the project's Resource Adequacy appropriately in shortlist selection. Allowing Sellers to pay damages, rather than incur an Event of Default for failure to have achieved FCDS by the IEDD, provides greater flexibility for Sellers to deal with unexpected transmission delays. Additionally, PG&E will~~

~~continue to monitor challenges related to project transmission and interconnection and adjust its RPS Solicitation Protocol to reflect future market conditions.~~

### ~~5.6~~5.5 ~~PG&E's~~ Risk-Adjusted Analysis ~~Accounts for Estimated Compliance Delays and Impacts PG&E's Procurement Decisions~~

PG&E employs both a deterministic and stochastic approach to quantifying its remaining need for incremental renewable volumes. ~~Deliveries~~As described further in Section 6, deliveries from projects experiencing considerable development challenges associated with project financing, permitting, transmission and interconnection, among others, are excluded from PG&E's net short calculation.

PG&E's experience with prior solicitations is that developers often experience difficulties managing some of the development issues described above. As described in Section 8, PG&E's current expected RPS need calculation incorporates a ~~statutory~~ minimum margin of procurement to account for some anticipated project failure and delays in PG&E's existing portfolio, which are captured in PG&E's deterministic model. These deterministic results are time~~-~~-sensitive and do not account for all of the risks and uncertainties that can cause substantial swings in PG&E's portfolio.

While it has made reasonable efforts to minimize risks of project delays or failures in an effort to comply with the 33% RPS Program procurement targets, PG&E cannot predict with certainty the circumstances~~,~~—or the magnitude of the circumstances~~,~~—that may arise in the future affecting the renewables market or individual project performance~~. PG&E's ability to comply with its RPS procurement requirement targets remains contingent on a number of factors outside of its control, as outlined in greater detail above in subsections 5.1 and 5.2~~.

## 6 Risk Assessment

Dynamic risks, such as the factors discussed in Section 5 that could lead to potential compliance delays, directly affect PG&E's ability to plan for and meet compliance with the RPS~~.~~ requirements. To account for these and additional uncertainties in future procurement, PG&E models the demand-side risk of retail sales variability and the supply-side risks of generation variability, project failure, curtailment, and project ~~commercial online dates~~delays in quantitative analyses.

Specifically, PG&E uses two approaches to modeling risk: (1) a deterministic model; and (2)~~-~~ a stochastic model. The deterministic model tracks the expected values of PG&E's RPS target and ~~RPS~~ deliveries to calculate a "physical net short," which represents ~~the best~~a point-estimate forecast of PG&E's RPS position and constitutes a reasonable minimum margin of procurement, as required by the RPS statute. These deterministic results serve as the primary inputs into the stochastic model. The stochastic model[49] accounts for additional compounded and interactive effects of various uncertain variables on PG&E's portfolio to suggest a procurement strategy at least cost within a designated level of non-compliance risk. The stochastic model provides target procurement volumes for each compliance period, which result in a designated Bank size for each compliance period. The Bank is then primarily utilized as Voluntary Margin of Procurement or VMOP to mitigate dynamic risks and uncertainties and ensure compliance with the RPS.

This section describes in more detail PG&E's two approaches to risk mitigation and the specific risks modeled in each approach~~ and PG&E's two approaches to risk mitigation~~. Section 6.1 identifies the three risks accounted for in PG&E's deterministic model. Section 6.2 outlines the ~~three~~ four additional risks accounted for in PG&E's

49 The stochastic model specifically employs both Monte Carlo simulation of risks and genetic algorithm optimization of procurement amounts. A Monte Carlo simulation is a computational algorithm commonly used to account for uncertainty in quantitative analysis and decision making. A Monte Carlo simulation provides a range of possible outcomes, the probabilities that they will occur and the distributions of possible outcome values. A genetic algorithm is a problem-solving process that mimics natural selection. That is, a range of inputs to an optimization problem are tried, one-by-one, in a way that moves the problem's solution in the desired direction—higher or lower—while meeting all constraints. Over successive iterations, the model "evolves" toward an optimal solution within the given constraints. In the case of PG&E's stochastic model, a genetic algorithm is employed to conduct a first-order optimization to ensure compliance at the identified risk threshold while minimizing cost.

stochastic model. Section 6.3 describes how the risks described in the first two sections are incorporated into ~~the deterministic and stochastic~~both models~~. This includes~~, including details ~~as to~~about how each model operates and the additional boundaries each sets on the risks. Section 6.4 notes how the two models help guide PG&E's optimization strategy and procurement need. Section 7 discusses the results for both the deterministic and stochastic models and introduces the physical and optimized net short calculations presented in Appendices C.~~1~~2a and C~~,2.~~.2b. Section 8 addresses PG&E's approach to the statutory minimum and voluntary margins of procurement.

### 6.1 Risks Accounted for in ~~the~~ Deterministic Model

PG&~~E employs a~~E's deterministic approach ~~to developing a risk-adjusted forecast of RPS-eligible deliveries from its existing portfolio. Specifically, this approach~~ models three key risks:

1) **Standard Generation Variability:** the assumed level of deliveries for categories of online RPS projects.

2) **Project Failure:** ~~a~~the determination of whether or not the contractual deliveries associated with a project ~~under~~in development should be excluded entirely from the forecast because of the project's relatively high risk of failure or delay.

3) **Project ~~Commencement Dates~~Delay:** the ~~assumed commencement~~monitoring and adjustment of ~~deliveries for projects included in~~project start dates based on information provided by the ~~model (so~~counterparty (as long as deliveries commence within the allowed delay provisions in the contract).

The table below shows the methodology used to calculate each of these risks, and to which category of projects in PG&E's portfolio the risks apply~~ to~~. More detailed descriptions of each risk are described in the subsections below.

**TABLE 6-1**
**PACIFIC GAS AND ELECTRIC COMPANY**
**DETERMINISTIC MODEL RISKS**

| RISK | METHODOLOGY | APPLIES TO |
|---|---|---|
| **Standard Generation Variability** | • ~~95% deliveries for Non-hydro QFs~~<br>• ~~100% deliveries for all other projects~~<br>• ~~PG&E's latest internal~~For non-QF projects executed post-2002, 100% of contracted volumes<br>• For non-hydro QFs, typically based on an average of the three most recent calendar year deliveries<br>• Hydro QFs, UOG and IDWA generation projections are updated to reflect the most recent hydro forecast ~~updates~~. | Online Projects |
| **Project Failure** | • ~~Under development~~In Development projects with high likelihood of failure are labeled "OFF" (0%- deliveries assumption)<br>• All other ~~Under~~In Development projects are "ON~~," that is, they are assumed to deliver~~" (assume 100% of ~~forecasted volumes~~contracted delivery) | ~~Under~~In Development Projects |
| **Project ~~Commencement Dates~~Delay** | • Professional ~~Judgment~~judgment / Communication with counterparties | Under Construction Projects / Under Development Projects / Approved Mandated Programs |

### 6.1.1 Standard Generation Variability

With respect to its operating projects, PG&E's forecast is ~~based on contract volumes or a blended~~divided into three~~-year average output. PG&E forecasts~~ categories: non-Qualifying Facilities ("QF"); non-hydro ~~QF~~ QFs; and hydro projects~~ at 95% of their three-year average output, with the slight reduction based on the observation that,~~. The forecast for ~~a variety of reasons, these older resources (as a portfolio) have tended to under-deliver when compared to their average historical performance. PG&E also adjusts its current-year hydro projections to reflect its best available projections~~non-QF projects is based on contracted volumes. The forecast for non-hydro ~~conditions. In future years, PG&E assumes~~ QFs is based on the average of the three most recent calendar year deliveries. The forecast for hydro ~~will reach and~~

~~maintain generation levels equivalent to an~~QFs is typically based on historical production, calendar year deliveries, and regularly updated with PG&E's latest internal hydro updates. The UOG and Irrigation District and Water Agency ("IDWA") forecast is based on PG&E's latest internal hydro updates. Future years' hydro forecasts assume average water year production. These assumptions are included in this RPS Plan as Appendix G.

### 6.1.2 Project Failure

To account for the development risks associated with securing project siting, permitting, transmission ~~and~~, interconnection, and ~~securing~~ project financing, PG&E uses the data collected through PG&E's project monitoring activities~~, as summarized in Section 4,~~ in combination with best professional judgment~~,~~ to ~~subjectively~~ determine a given project's ~~project~~ failure risk profile. PG&E categorizes its portfolio of contracts for renewable projects into two risk categories: OFF (represented with 0% deliveries) and ON (represented with 100% deliveries). This approach reflects the reality of how a project reaches full development; either all of the generation from the project comes online, or none of the generation comes online.

~~1.~~ 1. **OFF/Closely Watched** – PG&E excludes deliveries from the "Closely Watched" projects in its portfolio when forecasting expected incremental need for renewable volumes. "Closely Watched" represents deliveries from projects experiencing considerable development challenges as well as once-operational projects that have ceased delivering and are unlikely to restart. In reviewing project development monitoring reports, and applying their best professional judgment, PG&E managers may consider the following factors when deciding whether to categorize a project as "Closely Watched":

- Actual failure to meet significant contractual milestones (e.g., guaranteed construction start date, guaranteed commercial operation date, etc.).
- Anticipated failure to meet significant contractual milestones due to the project's financing, permitting, and/or interconnection progress or to other challenges (as informed by project developers, permitting agencies, status of CAISO

transmission studies or upgrades, expected interconnection timelines, and/or other sources of project development status data).

- Significant regulatory contract approval delays (e.g., 12 months or more after filing) with no clear indication of eventual authorization.
- Developer’s statement that an amendment to the PPA is necessary in order to preserve the project’s commercial viability.
- Whether a PPA amendment has been executed but has not yet received regulatory approval.
- Knowledge that a plant has ceased operation or plant owner/operator’s statement that a project is expected to cease operations.

Final forecasting assessments are project-specific and PG&E does not consider the criteria described above to be exclusive, exhaustive, or the sole criteria used to categorize a project as “Closely Watched.”[50]

~~2.~~ 2. **ON** – Projects in all other categories are assumed to deliver~~-~~ 100% ~~success rates~~of contracted generation over their respective terms. There are three main categories of these projects. The ~~majority of “ON”~~first category, which denotes projects that have achieved commercial operation or have officially begun construction, represents the majority of “ON” projects. Based on empirical experience and industry benchmarking, PG&E estimates that this population is highly likely to deliver~~ under their contract with PG&E. ~~. The second category of “ON” projects is comprised of those that ~~have not yet begun construction and~~ are ~~still under~~in development and are progressing with pre-construction development activities without foreseeable and significant delays. ~~Additionally, PG&E considers~~The third category of “ON” projects represents executed and future contracts from CPUC-~~approved~~ mandated programs~~ as “ON”.~~. While there may be some risk to specific projects being successful, because these volumes are

50 For instance, PG&E may elect to count deliveries from projects that meet one or more of the criteria if it determines, based on its professional judgment, that the magnitude of challenges faced by the projects do not warrant exclusion from the deterministic forecast. Similarly, the evaluation criteria employed by PG&E could evolve as the nature of challenges faced by the renewable energy industry, or specific sectors of it, change.

mandated, the expectation is that PG&E will replace failed volumes ~~and~~with replacement projects ~~would be online by 2020~~within a reasonable timeline.

### 6.1.3 Project ~~Commencement Date~~Delay

~~PG&E has an extensive process for monitoring~~Because significant project delays can impact the RNS, PG&E regularly monitors and updates the development status of RPS-eligible projects from PPA execution until commercial operation. Through periodic reporting, site visits, communication with counterparties, and other monitoring activities, PG&E tracks the progress of projects towards completion of major project milestones and develops estimates for the construction start (if applicable) and commercial operation of projects.~~ As significant project delays can impact the RNS, expected project commencement dates are confirmed and updated regularly.~~

## 6.2 Risks Accounted for in ~~the~~ Stochastic Model

~~Given that the~~The risk factors outlined in the deterministic model are inherently dynamic conditions that do not fully capture all of the risks affecting PG&E's RPS position. Therefore, PG&E has developed a stochastic model to better account for the compounded and interactive effects of various uncertain variables on PG&E's portfolio.~~[51]~~ PG&E's stochastic model assesses the impact of both demand-~~-~~ and-supply-~~-~~side variables on PG&E's RPS position from the following ~~three~~ four categories:

1) **Retail Sales Variability:** This demand-side variable is one of the largest drivers of PG&E's RPS position.
2) **Project Failure Variability:** Considers additional project failure potential beyond the "on-~~-~~off" approach in the deterministic model.

~~3~~3) **Curtailment:** Considers buyer-ordered (economic), CAISO-ordered or PTO-ordered curtailment.

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~~[51] Note that the stochastic model will be continually refined to better incorporate the risks that PG&E identifies. PG&E will potentially add capabilities and refinements to this model in the future, beyond the current form of the model which was used to define PG&E's 2014 optimization plan.~~

4) **RPS Generation Variability:** Considers additional RPS generation variability above and beyond the small percentages in the deterministic model.

When considering the impacts that these variables can have on its RPS position, PG&E organizes the impacts into two categories: ~~those impacts that (i) persist~~(1) persistent across years~~ versus (ii) those that are ~~; and (2) short-term (e.g., ~~an effect is~~effects limited to an individual year and ~~is ~~not highly correlated from year~~-~~-to~~-~~-year). Table 6-2 below lists the impacts by category, while showing the size of each variable's overall impact on PG&E's RPS position.

**TABLE 6-2**
**PACIFIC GAS AND ELECTRIC COMPANY**
**CATEGORIZATION OF IMPACTS ON RPS POSITION**

~~**Higher Impact on RPS Position**~~

| Impact | Categorization |
|---|---|
| **1. Retail Sales**~~:~~ **Variability:**<br>Changes in retail sales tend to persist beyond the current year (e.g.,~~ ~~ economic growth, ~~energy efficiency~~EE, CCA and DA, and distributed generation impacts). | **Variable and persistent**<br>(*If an outcome occurs, the effect persists through more than one year*). |
| **2. RPS Generation Variability:**<br>Variability in yearly generation is largely an annual phenomenon that has little persistence across time. | **Variable**<br>**and short-term**<br>(*If an outcome occurs, the effect may only occur for the individual year.*) |
| **3. Curtailment:**<br>Impact increases with higher penetration of renewables and will be persistent. | **Variable and persistent** |
| ~~3.~~**4. Project Failure**~~:~~ **Variability:**<br>Lost volume from project failure persists through more than one year. | **Variable and persistent** |

**Lower Impact on**

~~**Lower Impact on RPS Position**~~

### 6.2.1 Retail Sales Variability

PG&E's retail sales are impacted by factors such as weather, economic growth or recession, technological change, ~~energy efficiency~~EE, levels of ~~direct access/community choice aggregation~~DA and CCA participation, and distributed generation.  ~~To simulate the variability of annual retail sales volume,~~ PG&E ~~modeled~~ generates a distribution of the bundled retail sales for each year ~~as~~ [redacted] ~~with a standard deviation equal to~~ [redacted] ~~of the forecast for future years, and~~ [redacted] ~~of the forecast for the current year.~~[52] ~~PG&E has observed from historical data~~using a model that ~~forecast errors tend to persist across years, meaning that if a forecast of 2015 retail sales~~simulates thousands of possible bundled load scenarios.  Each scenario is ~~10% lower than the actual retail sales~~based on regression models for load in ~~2015, it is reasonable to expect the~~each end use sector as a function of weather and economic conditions with consideration of future policy impacts on EE, electric vehicles, and distributed generation.  However, the variability in load loss due to DA and CCA is not modeled in this same ~~vintage forecast for the subsequent year to also~~way.  As load loss due to DA is currently capped by California statute and cannot be ~~lower than the actual retail sales, and vice versa.~~[53]expanded without additional legislation, PG&E is not forecasting substantial increases in DA.  Load loss due to CCA departure is modeled as an expected value based on an increased forecast of CCA departure.  Because forecast errors tend to carry forward into future years, the cumulative impact of load forecast variability grows with time~~,~~ [redacted].

Appendix F.1 lists the resulting simulated retail sales and summary statistics for the period ~~2014-2033.  Appendix~~2015-2030.  Appendices F.~~5 shows~~5a and F.5b show the

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~~52 Parameters were obtained through analysis of bundled retail sales forecasts and actual retail sales made from 2000-2012.~~

~~53~~ [redacted]

resulting simulated RPS target when accounting for the retail sales variability for the period ~~2014-2033.~~ 2015-2030 in the 33% and 40% RPS, respectively.

### 6.2.2 RPS Generation Variability

Based on analysis of historical hydro generation data from [redacted], wind generation data from [redacted], and generation data from solar and other technologies where available, PG&E estimated a historical annual variability measured by the coefficient of variation of each resource type. [redacted] Due to significant variability in annual precipitation, small hydro demonstrates the largest annual variability (coefficient of variation of [redacted]). The remaining resource types range in annual variability from [redacted] for biomass and geothermal, [redacted] for solar PV and solar thermal to [redacted] for wind. Collectively, technology diversity helps to reduce the overall variation, because variability around the mean is essentially uncorrelated among technologies. Appendices F.3a and F.3b list the resulting simulated generation and summary statistics for the period 2015-2030 in the 33% and 40% RPS, respectively.

To better understand the wide range of variability of the above risks and thus, the need for a stochastic model to optimize PG&E's procurement volumes, Appendices F.4a and F.4b, combine the Project Failure and RPS Generation Variability factors into a "total deliveries" probability distribution, shows how these variables interact in the 33% and 40% RPS, respectively.

### 6.2.3 Curtailment

The stochastic model also estimates the potential for RPS curtailment. Curtailment can result from either buyer-ordered (economic), CAISO-ordered or PTO-ordered curtailment (the latter two driven by system stability issues, not economics). [redacted]

[redacted][54] These modeling assumptions will not necessarily align with the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance. Please see Section 11 for more information regarding curtailment.

#### ~~6.2.2~~6.2.4 Project Failure Variability

To model the project failure variability inherent in project development, PG&E assumes that project viability for a yet-to-be-built project is a function of the number of years until its contract start date. That is, a new project scheduled to commence deliveries to PG&E next year is considered more likely to be successful than a project scheduled to begin deliveries at a much later date. The underlying assumption is that both PG&E and the counterparty know more about a project's likelihood of success the closer the project is to its initial delivery date, and ~~a~~the counterparty may seek to amend or terminate a non-viable project before it breaches the PPA. Working from this assumption, PG&E assigns a probability of project success for new, yet-to-be-built projects equal to [redacted].

For example, a project scheduled to come online in five years or more is assumed to have a [redacted] chance of success. This success rate is based on experience~~,~~ and ~~although~~is reflective of higher project development success rates of PG&E's RPS portfolio in more recent years.

54 [redacted]

Although PG&E's current existing portfolio of projects may have higher rates of success, the actual success rate for projects in the long-term may be higher or lower. Projects that are re-contracted, in contrast, are modeled at a [redacted] success rate. ~~Appendix~~Appendices F.~~2 lists~~2a and F.2b list PG&E's simulated failure rate and summary statistics for the period ~~2014-2033.~~ 2015-2030 in the 33% and 40% RPS, respectively.

~~**6.2.3 RPS Generation Variability**~~

**6.2.5** ~~**Based on analysis of historical hydro generation data from**~~ [redacted]~~**, wind generation data from**~~ [redacted]~~**, and generation data from solar and other technologies where available, PG&E estimated a historical annual variability measured by the coefficient of variation of each resource type.**~~ [redacted] ~~**Due to significant variability in annual precipitation, small hydro demonstrates the largest annual variability (coefficient of variation of**~~ [redacted]~~**). The remaining resource types range in annual variability from**~~ [redacted]

**Comparison of Model Assumptions**

~~for biomass and geothermal,~~ [redacted] ~~for solar PV and solar thermal to~~ [redacted] ~~for wind. Collectively, technology diversity helps to reduce the overall variation, because variability around the mean is essentially uncorrelated among technologies. RPS generation variability also includes the potential for RPS curtailment.~~[55] ~~Appendix F.3 lists the resulting simulated generation and summary statistics for the period 2014-2033.~~

~~To better understand the wide range of variability of the above risks and thus the need for a stochastic model to optimize our procurement volumes, an additional Appendix F.4, combining the Project Failure and RPS Generation Variability factors into a "total deliveries" probability distribution, shows how these variables interact. Section 7~~

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~~55 Curtailment can result from either buyer-ordered (economic), CAISO-ordered or PTO-ordered curtailment (the latter two driven by system stability issues, not economics).~~

~~provides a more detailed summary of the results from PG&E's deterministic and stochastic modeling approach.~~

Table 6-3 below shows a comparison of how PG&E's deterministic and stochastic models each handle uncertainty with regard to retail sales, project failure, ~~and RPS generation~~RPS generation, and curtailment.  Section 7 provides a more detailed summary of the results from PG&E's deterministic and stochastic modeling approaches.

**TABLE 6-3**
**COMPARISON OF UNCERTAINTY ASSUMPTIONS**
**BETWEEN PG&E'S DETERMINISTIC AND STOCHASTIC MODELS**

| Uncertainty | Deterministic Model | Stochastic Model |
|---|---|---|
| 1) Retail Sales Variability | Uses most recent PG&E bundled retail sales forecast for next 5 years and ~~2010~~2014 LTPP for later years | ~~Based~~Distribution based on most recent (~~2014~~2015) PG&E bundled retail sales forecast~~,~~ [redacted] ~~standard deviation of the forecast in current year and~~ [redacted] ~~standard deviation of the forecast in future years~~. |
| 2) Project Failure Variability | Only turns "off" projects with high likelihood of failure per criteria. "On" projects assumed to deliver at Contract Quantity. | Uses [redacted] to model a success rate for all "on" yet-to-be-built projects in the deterministic model~~.(a)~~. Thus, for a project scheduled to come online in 5 years, the project success rate is [redacted]. This success rate is based on PG&E's experience that the further ahead in the future a project is scheduled to come online, the lower the likelihood of project success. Re-contracted projects are assumed to have a [redacted] success rate. |
| 3) RPS Generation Variability | ~~Assumes 5% reduction (i.e., 95% total success rate) for~~Non-QF projects executed post-2002, 100% of contracted volumes<br><br>For non-hydro QFs, typically based on an average of the three most recent calendar year deliveries<br><br>Hydro QFs, UOG and | Hydro: [redacted] annual variation<br>Wind: [redacted] annual variation<br>Solar: [redacted] annual variation<br>Biomass and Geothermal: [redacted] annual variation |

| | | |
|---|---|---|
| | IDWA generation projections are updated to reflect the most recent hydro forecast. | |
| ~~(a) The stochastic model uses generation forecasts from the April 2014 deterministic model.~~4) Curtailment[56] | None | 33% RPS Target: [redacted] of RPS requirement<br>40% RPS Scenario: [redacted] of RPS requirement through 2021, increasing to [redacted] in 2024 and beyond. |

### 6.3 How Deterministic Approach Is Modeled

~~PG&E uses its~~The deterministic model ~~to create~~is a snapshot in time of PG&E's current and forecasted RPS position and procurement need. The deterministic model relies on ~~best current~~currently available ~~data related to~~ generation data for ~~signed RPS projects, both~~executed online and ~~under~~in development~~,~~ RPS projects as well as PG&E's most recent bundled retail sales forecast. The results from the deterministic model determine PG&E's "physical net short," which represents the best current point~~-~~-estimate forecast of PG&E's RPS position today. The deterministic model should not be seen as a static target because the inputs are updated as new information is received.

### 6.4 How Stochastic Approach Is Modeled

The stochastic model adds rigor to the risk-adjustment embedded in the deterministic model—using Monte Carlo simulation—and optimizes its results to achieve the lowest cost possible given a specified risk of non-compliance and the stochastic model's constraints.

56 These modeling assumptions will not necessarily align with the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance.

The methodology for the stochastic model is as follows:

1) Create an optimization problem by establishing the (a) objectives, (b) inputs, and (c)~~-~~ constraints of the model.

a. The ~~objectives are~~objective is to~~: (1) identify the optimal RPS-eligible deliveries needed in the years~~ [redacted] ~~to ensure compliance and (2)~~ minimize procurement cost.

b. The inputs are a range of potential incremental RPS-eligible deliveries (new and re-contracted volumes[57]) in each year of the [redacted] ~~timeframe.~~~~[58]~~ [redacted] timeframe. The potential incremental procurement is restricted to a range of no less than zero and no more than [redacted] GWh, which is in addition to volumes available for re-contracting.[59]

c. The constraints are: (1) to keep PG&E's risk of non-compliance to less than [redacted]~~[60]~~ [redacted]; and (2) to restrict PG&E's Bank over time to the size necessary to meet compliance objectives within the specified risk threshold~~; and (3) to restrict potential incremental procurement from new projects in each of the modeled years~~ [redacted]~~.~~~~[61]~~ .

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57 Although the physical net short calculations do not include any assumptions related to the re-contracting of expiring RPS-eligible contracts, the stochastic model can ~~choose to~~also re-contract volumes ~~in order~~ to meet procurement need~~, for~~. Such re-contracting amounts are illustrative ~~purposes~~ only and not prescriptive.

~~58~~ [redacted]~~.~~

59 PG&E limited modeling to a maximum addition of [redacted] GWh per year in order to avoid modeling outcomes that required "lumpy" procurement patterns. Large swings in annual procurement targets could lead to boom/bust development cycles and could expose PG&E's customers to additional price volatility risk.

~~60~~ [redacted]

~~61 PG&E limited modeling to a maximum addition of~~ [redacted] ~~GWh per year in order to avoid modeling outcomes that required "lumpy" procurement patterns. Large swings in annual procurement targets could lead to boom/bust development cycles and could expose PG&E's customers to additional price volatility risk.~~

2) The stochastic model then solves the optimization problem by ~~trying~~examining thousands of combinations of procurement need in each year. For each of these combinations, the ~~stochastic~~ model ~~then~~ runs hundreds of iterations as part of its Monte Carlo simulation of uncertainty for each of the risk factors in the stochastic model to test if the constraints are met. If the solution for that combination of inputs fits within the given constraints, it is a valid outcome.

3) For each valid outcome, the mean Net Present Value ~~(~~(“NPV~~)~~”) cost of meeting that procurement need is calculated based on PG&E’s RPS forward price curve.

4) Finally, the model sorts the NPV of the potential procurement outcomes from smallest to largest, thus showing the ~~optimized solution~~optimal RPS-eligible deliveries needed in the years [redacted] to ensure compliance based on the modeled assumptions.

The modeled solution becomes a critical input into PG&E’s overall RPS optimization strategy, but the outputs are subject to further analysis based upon best professional judgment to determine whether factors outside the model could lead to better outcomes. For example, the model does not currently consider speculating on price volatility through sales of PG&E’s Bank in the near-term and additional incremental procurement in the long-term. Nor does the model consider the opposite strategy of ~~speculative~~advance procurement of RPS-eligible products in ~~2014~~2015 for purposes of reselling those products in the future at a profit. As a general matter, PG&E does not approach RPS procurement and compliance as a speculative enterprise and so has not modeled or otherwise proposed such strategies in this Plan. [redacted] However, PG&E will consider selling surplus non-bankable RPS volumes in its portfolio and, in doing so, may seek to sell surplus bankable volumes if it can still maintain an adequate Bank and if market conditions are favorable.

### 6.5 Incorporation of the Above Risks in the Two Models ~~Helps Determine~~Informs Procurement Need and ~~Evaluate~~ Sales Opportunities

Incorporating inputs from the deterministic model, the stochastic model provides results that lead to ~~open positions for each compliance period,~~a forecasted procurement need or SONS, expected Bank usage and thus an anticipated Bank size, for each compliance period. ~~These open positions~~ The SONS for the 33% and 40% RPS are shown in Row La of PG&E's Alternate RNS in ~~Appendix~~Appendices C.~~2. The portion of the Bank that will be used towards VMOP is intended to mitigate dynamic risks and uncertainties~~2a and ~~enables PG&E to sustain its compliance position while minimizing costs post-2020 within an acceptable level of compliance risk~~ C.2b.

The stochastic model does not provide guidance on potential sales of excess banked procurement at this time. ~~As~~ However, as PG&E encounters economic opportunities to sell volumes, PG&E will use the stochastic model to help evaluate whether the proposed sale will increase the cumulative non-compliance risk for [redacted] above the [redacted] threshold.

~~It is worth emphasizing that the current Bank estimates in this Plan should be seen as a snapshot in time rather than a static target. The results of both~~The results of both the deterministic and stochastic models are discussed further in Section 7 and minimum margin of procurement is addressed in Section 8.

## 7 Quantitative Information

As discussed in Section 6, PG&E's objectives for this RPS Plan are to both achieve and maintain RPS compliance and to minimize customer cost within an acceptable level of risk. To do that, PG&E uses both ~~the~~ deterministic and stochastic models ~~described in Section 6~~. This section provides details on the results of both models and references RNS tables provided in Appendix C. Appendices C.~~1~~1a and C.~~2. Appendix C.1~~1b presents the RNS in the form required by the *Administrative Law Judge's Ruling on Renewable Net Short* issued May 21, 2014 in R.11-05-005 ("ALJ RNS Ruling") and includes results from PG&E's deterministic model only, while

~~Appendix~~Appendices C.~~2 is~~2a and C.2b are a modified version of ~~Appendix~~Appendices C.~~1~~1a and C.1b to present results from both PG&E's deterministic and stochastic ~~model~~models. These modifications to the table are necessary in order for PG&E to adequately show its results from its stochastic optimization.

### 7.1 Deterministic Model Results

Results from the deterministic model under the 33% RPS target are shown as the physical net short in ~~row~~ Row Ga of Appendices C.~~1~~1a and C.~~2. Appendix~~2a, while the results from the deterministic model under the 40% RPS scenario are shown as the physical net short in Row Ga of Appendices C.~~1 provides~~1b and C.2b. Appendices C.1a and C.1b provide a physical net short calculation using PG&E's Bundled Retail Sales Forecast for years ~~2014-2018~~2015-2019 and the LTPP ~~methodology~~sales forecast for ~~2019-2030~~2020-2035, while ~~Appendix~~Appendices C.~~2 relies~~2a and C.2b rely exclusively on PG&E's internal Bundled Retail Sales Forecast. Following the methodology described in Section 6.1, PG&E currently estimates a long-term volumetric success rate of ~~87~~approximately 99% for its portfolio of executed-but-not-operational projects. The annual forecast failure rate used to determine the long-term volumetric success rate is shown in Row Fbb of Appendices C.~~1~~2a and C.~~2~~2b. This success rate is ~~not only~~ a snapshot in time and is ~~highly dependent on PG&E's portfolio, but is~~ also impacted by ~~the~~ current conditions in the renewable energy industry, discussed in more detail in Section 5, as well as project-specific conditions.

In addition to the current long-term volumetric success rate, Rows Ga and Gb of Appendices C.~~1~~2a and C.~~2~~2b depict PG&E's expected compliance position using the current expected need scenario before application of the Bank~~, and demonstrate that PG&E will meet its second (2014-2016) Compliance Period RPS requirements. However, before applying excess procurement from the first and second compliance periods, PG&E anticipates a small physical net short for the third (2017-2020)~~

~~Compliance Period RPS requirements. As illustrated by the results of its current expected need scenario analysis shown in Row Ga of Appendix C.2, the deterministic model shows a physical net short of approximately 2,300 GWh in 2020 markedly increasing to approximately 5,300 GWh in 2022.[62] This significantly increased need in the early part of the next decade is driven by a large volume of expiring contracts in that timeframe.~~ .

#### 7.1.1 33% RPS Target Results

Under the current 33% RPS target, PG&E is well-positioned to meet its second (2014-2016) and third (2017-2020) compliance period RPS requirements. As shown in Row Gb of Appendix C.1b, the deterministic model shows a forecasted second compliance period RPS Position of 30.3% and a third compliance period RPS position of [redacted]. Row Ga of Appendix C.2a also shows a physical net short of approximately 500 GWh beginning in 2022.

#### 7.1.2 40% RPS Scenario Results

Under a 40% RPS scenario, PG&E is forecasted to meet its second (2014-2016) and third (2017-2020) compliance period RPS requirements. As shown in Row Gb of Appendix C.2b, PG&E has a forecasted second compliance period RPS Position of 30.3% and a third compliance period RPS position of [redacted]. Row Ga of Appendix C.2b shows a physical net short of approximately 3,000 GWh beginning in 2022.

### 7.2 Stochastic Model Results

This subsection describes the results from the stochastic model and the SONS calculation ~~that is based~~for both the current 33% RPS target and a 40% RPS scenario. All assumptions and caveats stated in ~~part on those~~the discussion of the 33% RPS target results~~. Since~~ apply to the 40% RPS scenario results, unless otherwise stated.

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~~[62] The net short numbers in the deterministic model do not include any volumes that may be executed as part of the 2013 RPS RFO.~~

However, note that the 40% RPS scenario results apply to this particular RPS scenario only, and PG&E's optimization strategy may differ under other scenarios that have a different RPS target or timeline. Because PG&E uses its stochastic model to ~~optimize~~inform its RPS procurement, PG&E has created an Alternate RNS in Appendix C.~~2.~~ 2a for the current 33% RPS target and Appendix C.~~1 provides a misleading~~2b for the 40% RPS scenario. Appendices C.1a and C.1b provide an incomplete representation of PG&E's optimized net short, as the formulas embedded in the RNS form required by the ~~May 21, 2014~~ ALJ RNS Ruling do not enable PG&E to capture its stochastic modeling inputs and outputs. In ~~Appendix~~Appendices C.~~2~~2a and C.2b, two additional rows have been added. Rows Gd and Ge show the stochastically-adjusted ~~physical~~ net short ~~(in GWh and as a percentage),~~("SANS"), which incorporates the risks and uncertainties addressed in the stochastic model. This is prior to any applications of the Bank, but includes additional procurement needed for maintaining an optimized ~~bank~~Bank size. Additionally, PG&E has modified the calculations in Rows La and Lb in order to more accurately represent PG&E's SONS.

#### 7.2.1 "Stochastically-Optimized Net Short" to Meet Non-Compliance Risk Target ~~of~~ [redacted] – 33% RPS Target

~~In order to~~To evaluate possible procurement strategies, PG&E selected a cumulative [redacted] ~~time period~~([redacted]) non-compliance risk target of [redacted], which PG&E views as the maximum reasonable level of non-compliance risk. Figure 7-1 shows the model's forecasted procurement need and resulting Bank usage under the current 33% RPS. Under this projection, a portion of the Bank is used to meet PG&E's compliance need beginning in [redacted], the first year showing a stochastically-adjusted net short, and continuing throughout the decade, while reserving a portion of the Bank to be maintained as VMOP to manage risks discussed in Section 6. Appendix C.2a provides the detailed results. Annual forecasted Bank usage is shown in Row Ia of this Appendix. After accounting for Bank usage, the first year of incremental procurement need is forecasted as [redacted]. This compliance period need represents PG&E's SONS, which is detailed in Row La. The SONS for [redacted] is approximately [redacted] GWh, which increases to approximately [redacted] GWh by 2030. The [redacted] SONS is [redacted] than the physical net short in Row Ga for [redacted], as the SONS [redacted].

[redacted]

[redacted]

[redacted]~~annual and~~

Because the stochastic model inputs change over time, these estimates should be seen as a snapshot in time rather than a static target and the procurement targets will be re-assessed as part of future RPS Plans.

#### 7.2.2 Bank Size Forecasts and Results – 33% RPS Target

Figure 7-2 shows PG&E's current and forecasted cumulative ~~non-compliance risk and end-of-year mean net position (Bank size). The total risk of non-compliance is cumulative over the~~ [redacted] ~~period. For instance, while the annual non-~~Bank from the first compliance ~~risk forecast ranges from~~ [redacted] ~~to~~ [redacted] ~~from~~ [redacted]~~, the~~ period through 2030. PG&E's total ~~risk~~Bank size as of ~~non-~~the end of compliance ~~during the~~ [redacted] period ~~is~~ [redacted]~~.~~ is approximately 900 GWh, shown as existing Bank in Figure 7-2. The stochastic model's results currently project PG&E's Bank size to [redacted] GWh by [redacted] (as shown in Figure 7-2, as well as in Appendix C.2a, Row J). [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

There is a trade-off between non-compliance risk and Bank size. ~~Lower risk scenarios maintain a~~ A larger Bank size~~, which~~ decreases non-compliance risk. However, a larger Bank size may also increase ~~current~~ procurement costs. Higher risk scenarios would result in a lower Bank size and, as discussed above, would increase PG&E's probability of being in a position in which PG&E ~~may~~might need to make unplanned purchases to comply with its RPS requirement. In that situation, PG&E might not be able to avoid higher procurement costs due to the potential for upward pressure on prices caused by the need for unplanned purchases~~ to comply~~.

> ~~The stochastic model's results currently project PG&E's~~ [redacted] ~~GWh by~~ [redacted] ~~(as shown in Figure 7-1, as well as in Appendix C.2, Row J).~~ [redacted] ~~of the Bank will be maintained as VMOP to manage risks as discussed above. Because the stochastic model inputs change over time, forecasts of the Bank size will also change, so these estimates should be seen as a snapshot in time rather than a static target.~~
>
> ~~By providing Bank levels that maintain PG&E's RPS compliance at a desired probability threshold, the stochastic model forecasts PG&E's~~

~~compliance period need and suggests procurement~~[63] ~~to meet that need in a lowest-cost manner including maintaining an adequate VMOP in the form of the remaining Bank. This compliance period need represents PG&E's SONS, which is detailed in Row La of Appendix C.2. The SONS for the third compliance period is approximately~~ [redacted] ~~GWh, which increases to approximately~~ [redacted] ~~GWh by 2023. The third compliance period SONS is~~ [redacted] ~~than the physical net short shown in Row Ga of Appendix C.2 for the third compliance period, as the SONS accounts for~~ [redacted]~~. Additionally, the physical net short includes~~ [redacted]~~. For 2020 and the third compliance period, procuring up to 1,600 GWh per year is within the range of risk of non-compliance established by PG&E. This amount will allow for some flexibility in the 2013 RPS RFO procurement outcomes and for some potential project failure for quantities procured prior to 2020 while still meeting the RPS need in 2020.~~

~~In addition to procuring up to 1,600 GWh per year as part of the 2014 RPS RFO, PG&E intends to procure steady, incremental volumes each year across the next several years to average variability in prices over time. However, because the SONS is based on a dynamic set of inputs, the procurement target for later periods will be re-assessed as part of future RPS Plans.~~

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~~63 These procurement quantities embed a mix of both re-contracted and new projects. The former are assumed to have no project failure and the latter are assumed to have some project failure between contract execution and commercial operation. In this scenario, the minimum cost optimization solution embeds assumed project failure quantities of approximately~~ [redacted]~~. Note, however, the next best optimization solution had only a slightly higher total cost with a different mix of re-contracted and new projects. That is, PG&E need not procure the exact proportion of re-contracted and new projects to achieve a low-cost outcome.~~

~~PG&E's 2014 RPS Procurement goal of 1,600 GWh per year is in addition to any volumes that may be executed as part of the 2013 RPS RFO, which offers are currently under negotiation. However, any volumes that might be procured outside of PG&E's RPS Solicitation would be counted against the 1,600 GWh per year goal. In addition, this amount includes any incremental volumes that may come from any proposed new or additional renewables procurement mandates. Thus, if new long-term procurement mandates equaled, for example, 1,600 GWh in 2020, PG&E's long-term procurement need for 2020 and beyond in this Plan would be reduced to zero.~~

[redacted]

~~**7.2.2 Bank Size Forecasts and Results**~~

### 7.2.3 Minimum Bank Size – 33% RPS Target

PG&E performed a simulation of variability in PG&E's future generation and RPS compliance targets over [redacted] years—i.e., the amount of the RPS generation ("delivery") net of RPS compliance targets ("target")—and found that a Bank size of ~~approximately~~ [redacted] ~~GWh~~at least [redacted] is the minimum Bank necessary to maintain a cumulative non-compliance risk of no greater than [redacted]. The difference between delivery and target can be thought of as the potential "need" (if- negative) or "surplus" (if positive) that PG&E has in any one- year.

Figure 7-~~2~~3 shows this distribution based on the deterministic procurement necessary to meet the expected RPS targets with expected generation ~~over the period of~~during [redacted]. This time period was selected as it best represents a "steady

state" period when the Bank approaches a minimum level and moderate incremental procurement is required to maintain compliance. Note that given the uncertainty around the inputs in the stochastic model, without a Bank to accommodate such uncertainty, the amount of RPS generation is almost as likely to miss the RPS target as exceed it. One standard deviation over [redacted] is approximately [redacted] GWh, as indicated on Figure 7~~-2~~-3. That is, given this particular procurement scenario, about 68% of the simulations have a difference that is up to plus or minus approximately [redacted] GWh~~ of zero. ~~.

However, this does not suggest that a Bank of [redacted] [redacted] GWh would be adequate to cover potential shortfalls over this [redacted]-year period. It would result in an unacceptable non-compliance risk over [redacted] of approximately [redacted]. Thus, PG&E must maintain a Bank size higher than this amount to limit the risk of non-compliance to an acceptable level. Based on current model assumptions and inputs, Figure 7-3 shows that approximately [redacted] of the time, PG&E would have a greater than [redacted] GWh deficit in meeting compliance for [redacted].

[redacted]

[redacted]

~~7.3~~

AS [redacted]

[redacted]

~~By adhering to the stochastic model's long-term procurement strategy, the model currently projects that this could lead to PG&E's forecasted~~ [redacted] ~~GWh. This is consistent with the approximate~~ [redacted] ~~GWh deficit shown in Figure 7-2. Based on current model assumptions and inputs, Figure 7-2 shows that approximately~~ [redacted] ~~of the time, PG&E would have a greater than~~ [redacted] ~~GWh deficit in meeting compliance for~~ [redacted]~~.~~

stated in Section 7.2.2, the stochastic model's results show PG&E's forecasted [redacted] PG&E's strategy is to procure steady, incremental volumes in order to avoid the need to procure extremely large volumes in any single year to meet compliance needs and maintain minimum Bank levels.

[redacted]

Because the model inputs change over time, estimates of the Bank size resulting from the implementation of the procurement plan will also change. In practice, the actual outcome will more likely be a mix of factors both detracting from and contributing to meeting the target, which is what the probability distribution in Figure 7-~~2~~3 illustrates.

#### 7.2.4 Stochastically-Optimized Net Short to Meet Non-Compliance Risk Target – 40% RPS Scenario

Figure 7-4 shows the model's forecasted procurement need and recommended Bank usage in the 40% RPS scenario. Under this projection, a portion of the Bank is used to meet PG&E's compliance need beginning in [redacted], while reserving a portion of the Bank to be maintained as VMOP to manage risks discussed in Section 6. Appendix C.2b provides the detailed results. Annual forecasted Bank usage can be seen in Row Ia of this Appendix. The first year of procurement need is currently forecasted as [redacted]. This compliance period need represents PG&E's SONS, which is detailed in Row La. The SONS for [redacted] is approximately [redacted] GWh, which increases to approximately [redacted] GWh by [redacted]. The [redacted] SONS is [redacted] than the physical net short shown in Row Ga for [redacted].

[redacted]

[redacted]

[redacted]

### 7.2.5 Bank Size Forecasts and Results – 40% RPS Scenario

Figure 7-5 shows PG&E's current and forecasted cumulative Bank from Compliance Period 1 through 2030 under a 40% RPS scenario. PG&E's total Bank size as of the end of Compliance Period 1 is approximately 900, shown as existing Bank in Figure 7-5. The stochastic model's results currently project PG&E's [redacted] (as shown in Figure 7-5, as well as in Appendix C.2b, Row J).

[redacted]

[redacted]

[redacted]

#### 7.2.6 Minimum Bank Size – 40% RPS Scenario

Using a similar approach as described in Section 7.2.3, under a 40% by 2024 scenario, a minimum Bank size of at least [redacted] GWh is necessary to maintain a cumulative non-compliance risk of no greater than [redacted]. The minimum Bank size in this scenario is greater than the Bank required for the 33% RPS target, as more volumes are required to meet the higher RPS, but also [redacted].

[redacted]

[redacted]

The stochastic model's procurement strategy results show PG&E's forecasted [redacted]. Based on current model assumptions and inputs, Figure 5-6 shows that approximately [redacted] of the time, PG&E would have a greater than [redacted] GWh deficit in meeting compliance for [redacted].

### ~~7.4~~7.3 Implications for Future Procurement

~~Overall,~~ PG&E plans to continually refine both its deterministic and stochastic models, thus the procurement strategy outlined above is applicable to this RPS ~~plan~~Plan only. In ~~subsequent~~future years, PG&E's procurement strategy will likely change, based on updates to the data and algorithms in both models. Additionally, PG&E will continue to assess the value to its customers of sales of ~~excess banked~~surplus procurement. Consistent with the Commission's adopted RNS methodology, PG&E's physical net short and cost projections do not include any projected sales of bankable contracted deliveries. [redacted] However, PG&E will consider selling non-bankable surplus volumes in its portfolio and, in doing so, may identify and propose in the future opportunities to secure value for its customers through the sale of bankable surplus procurement. PG&E will update its physical RNS if it executes any such sale agreements and will include in its optimized RNS and SONS specific future plans to sell RPS procurement.

## 8 Margin of Procurement

~~PG&E intends to procure steady and moderate incremental long-term resources over the next several years to ensure that it can reach, and sustain, the 33% RPS targets and to maintain an adequate Bank of surplus RPS volumes that ensures PG&E achieves the state's policy objectives in a cost-effective manner. In order to achieve these objectives, PG&E intends to include two components of margins of procurement: (1) a statutory~~When analyzing its margin of procurement, PG&E considers two key components: (1) a statutory minimum margin of procurement to address some anticipated project failure or delay, for both existing projects and projects under contract but not yet online, that is accounted for in PG&E's deterministic model; and (2) a VMOP, which aims to mitigate the additional risks and uncertainties that are accounted for in PG&E's stochastic model. Specifically, PG&E's VMOP intends to (a) mitigate risks associated with short-term variability in load~~,~~; (b) protect against project failure or delay exceeding forecasts~~,~~; and (c) manage variability from RPS resource generation~~; in~~. In so doing, PG&E's VMOP helps to eliminate the need at this time to procure long~~-~~-term contracts above the 33% RPS target by creating a buffer that enables PG&E to manage the year~~-~~-to~~-~~-year variability that result from risks (a)-(c). This section discusses both of these components and how each is incorporated into PG&E's quantitative analysis of its RPS need.

~~This section discusses both of these margins of procurement and how each is incorporated into PG&E's quantitative analysis of its RPS need and the development of its 2014 RPS procurement goals.~~

### 8.1 Statutory Minimum Margin of Procurement

The RPS statute requires the Commission to adopt an "appropriate minimum margin of procurement above the minimum procurement level necessary to comply with the [RPS] to mitigate the risk that renewable projects planned or under contract are delayed or canceled."[64] PG&E's reasonableness in incorporating this statutory minimum margin of procurement into its RPS procurement strategy is one of the factors the Commission must consider if PG&E were to seek a waiver of RPS enforcement because conditions beyond PG&E's control prevented compliance.[65]

As described in more detail in Section 6, PG&E has developed its risk-adjusted RPS forecasts using a deterministic model that: (1) excludes volumes from contracts at risk of failure from PG&E's forecast of future deliveries; and (2) adjusts expected commencement of deliveries from contracts whose volumes are included in the model (so long as deliveries commence within the allowed delay provisions in the contract). ~~Currently these adjustments result in a long-term volumetric reduction in expected deliveries from executed-but-not-operational contracts of approximately 13%, or a long-term volumetric success rate of 87% for PG&E's portfolio of executed-but-not-yet-operational projects. PG&E's current long-term failure rate calculation is based on its best current professional judgment regarding the likelihood of project performance, but the rate of actual project failures or delays may prove to be higher or lower.~~ PG&E

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**64** Cal. Pub. Util. Code § 399.13(a)(4)(D).

**65** *Id*~~.at~~., § 399.15(b)(5)(B~~) (~~)(iii).

considers this deterministic result to be its current statutory margin of procurement.[66] However, as discussed in Sections 6 and 7, these results are variable and subject to change, and thus PG&E does not consider this statutory margin of procurement to sufficiently account for all of the risks and uncertainties that can cause substantial variation in PG&E's portfolio. To better account for these risks and uncertainties, PG&E uses its stochastic model to ~~propose~~assess a VMOP, as described further~~-~~ below.

### 8.2 Voluntary Margin of Procurement

The RPS statute provides that in order to meet its compliance goals, an IOU may voluntarily propose a margin of procurement above the statutory minimum margin of procurement.[67] As discussed further in Sections 6 and 7, PG&E plans to use a portion of its Bank~~ primarily~~ as a VMOP to manage additional risks and uncertainties accounted for in the stochastic model.

While PG&E's current optimization strategy projects [redacted]~~, PG&E believes it would be imprudent to use its entire projected Bank toward meeting the 33% RPS compliance target, rather than to cover unexpected demand and supply variability and project failure or delay exceeding forecasts from projects not yet under contract.~~[redacted]

66 In the past PG&E has seen higher failure rates from its overall portfolio of executed-but-not-operational RPS contracts. However, as the renewables market has evolved~~—~~—and projects are proposed to PG&E at more advanced stages of development~~—~~—PG&E has observed a decrease in the expected failure rate of its overall portfolio. ~~Put another way, the~~The more recent projects added to PG&E's portfolio appear to be significantly more viable than some of the early projects in the RPS Program, resulting in lower current projections of project failure than have been discussed in past policy forums. However, its revised success rate assumption (from 87% to 99%) also reflects several recent contract terminations from PG&E's portfolio due to and an update to the "Closely Watched" category described in Section 6.

67 *Id*~~. at §~~., § 399.13(a)(4)(D).

[redacted]. When used as VMOP, the Bank will help to avoid long-term over-procurement above the 33% RPS target, and will thus reduce long-term costs of the RPS Program. Since the model inputs change over time, estimates of the Bank and VMOP are not a static target and will change, so these estimates should be seen as a snapshot in time. Additional discussion on the need for and use of the Bank and VMOP are included in Sections 6 and 7.

Additionally, as a portion of the Bank will be used as VMOP, PG&E will continue to reflect zero volumes in Row D of its RNS tables, consistent with how it has displayed the VMOP in past RNS tables.

# 9 Bid Selection Protocol~~, Including Least-Cost, Best-Fit Methodologies~~

## ~~9.1 Overview of 2014 RPS Solicitation Protocol and RPS Form PPA~~

~~The schedule for PG&E's 2014 RPS Solicitation and all solicitation documents are included in the RPS Solicitation Protocol. PG&E's 2014 RPS Form PPA is attached to the Solicitation Protocol in Appendix H. Redlines showing changes to the Solicitation Protocol (including the RPS Form PPA) are found in Appendix I.~~

### ~~9.1.1 2014 RPS Procurement Goals~~

~~PG&E proposes to procure moderate volumes of long-term resources over the next several years to ensure that it can reach, and sustain, the 33% RPS targets. For this purpose, PG&E seeks to procure between zero and 1,600 GWh per year in the 2014 RPS Solicitation.~~[68]

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[68] ~~PG&E is seeking up to 1,600 GWh per year for the 2014 RPS RFO. However, whether or not PG&E executes PPAs arising out of the 2014 RPS Solicitation is dependent on whether PG&E and the shortlisted bidders can reach mutual agreement on specific and definitive terms, some of which may differ significantly from those in the RPS Form PPA. PG&E reserves the right not to execute any PPA.~~

~~PG&E will seek long-term offers from all three product content categories. To meet its zero to 1,600 GWh per year need, PG&E is seeking long-term offers with contract start dates in 2020 or later.~~

~~PG&E's interest in, and requests for, long-term Category 2 and 3 products is contingent upon a finding that the offers are within the portfolio content category limitation for each respective compliance period and will not be deducted from bankable volumes. PG&E notes that its ability to use such Category 2 and 3 products for compliance diminishes over time, and therefore its need for those products will also diminish over time.~~

~~Category 3 products are a limited, but potentially important, part of PG&E's procurement strategy as they may provide a low-cost compliance option for PG&E's customers while at the same time potentially mitigating integration and other operational challenges associated with incremental procurement from typical Category 1 or Category 2 procurement. If PG&E decides to execute Category 3 transactions as part of the 2014 RPS RFO, this procurement would make~~ [redacted] ~~of PG&E's high-end 2014 Solicitation target of 1,600 GWh per year. The Category 3 volume would likely represent no more than~~ [redacted] ~~of the high-end 2014 RPS RFO procurement target.~~[69]

~~Projects in PG&E's service territory are preferred, as are projects with characteristics that merit a higher viability score, such as existing assets or projects with greater interconnection cost certainty. Out-of-state offers will continue to be evaluated for all three product~~

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69 [redacted]

~~categories. Category 1 and Category 2 products will be analyzed to determine their ability to qualify under the specific regulatory definitions of those product types. Category 2 projects should not require PG&E to take on delivery and cost risks any different from Category 1 projects.~~

~~The offers selected will have the best combination of value, viability and qualifications based on the evaluation criteria specified in the 2014 RPS Solicitation Protocol. Additionally, PG&E will use as a screening tool the PVC issued by the Commission on June 2, 2011.~~

**~~9.2 Key Changes in the 2014 RPS Solicitation Process and Form PPA~~**

~~The RPS Solicitation Protocol describes how PG&E will conduct its RFO, who is eligible to participate and how PG&E will evaluate and select offers. The Protocol includes several attachments, including a form PPA for Category 1 and 2 products (Attachment H1) products, a separate Form of REC Purchase Agreement for Category 3 products (Attachment H2), and a form agreement for the sale of RPS products with terms of 5 years or less (Attachment H3). The Protocol also articulates PG&E's preference for products in further detail.~~

~~PG&E has made changes to the 2014 RPS Form PPA and 2014 RPS Solicitation Protocol to reflect changing market conditions and PG&E's RPS need. These revisions are intended to create greater incentives for full contract performance. Given the dynamic nature of the renewables industry, market, and regulatory environment, PG&E may make further modifications, subject to the Commission approval process described in D.14-11-042, to the 2014 Solicitation Protocol and 2014 RPS Form PPA as market conditions evolve prior to solicitation issuance in order to minimize operational challenges, maximize the value of projects to PG&E customers, and minimize any potential future contract disputes.~~

~~Below are some of the key changes for the 2014 Solicitation. Potential bidders should review the actual RPS Form PPA at Attachment H since these~~

~~descriptions are general and not intended to be comprehensive or contractually binding.~~

~~Eligibility: Consistent with D.14-11-042, PG&E has reduced the minimum eligible project size from 1.5 MW to 0.5 MW. Projects must have an application deemed complete from the lead land use agency. Offers submitted in this Solicitation must have a start date of 2020 or later. PG&E's preference is for start dates after 2020.~~

~~Storage: Consistent with PG&E's 2013 RPS Solicitation Protocol, PG&E is seeking offers from RPS projects that include storage that is charged by the renewable resource. For the 2014 RFO, PG&E is requiring any offer with storage to submit an offer variant without storage, so that PG&E may consider the incremental value provided by the storage component.~~

~~Operational Flexibility: In recognition of the increasing operational challenges that additional resources are placing on the system, and the growing need for the flexibility to economically bid RPS resources into the CAISO markets, PG&E's 2014 RPS Form PPA has been modified to provide PG&E with the ability to bid the resource into the CAISO and address overgeneration and negative pricing situations which are likely to become more common in the future on the CAISO grid. Pursuant to D.14-11-042, PG&E is seeking two variants of each bid: (1) one primary bid with an uncapped option for economic curtailment; and (2) one alternative bid with a cap on economic curtailment, with the cap to be proposed by the bidder. PG&E has included contract language associated with the primary bid variant in its 2014 RPS Form PPA and will negotiate with Sellers to modify that language if it accepts an alternative bid variant. PG&E also maintains the provision from the 2013 RPS Form PPA requiring Sellers to specify a single price for buyer curtailment hours, rather than proposing a tiered pricing. Sellers' alternative bids offering less than full~~

~~operational flexibility will be valued according to the methodology described in Attachment K to the Solicitation Protocol.~~

~~Resource Adequacy: In its 2013 RPS Form PPA, PG&E required that Sellers be fully deliverable at IEDD. In recognition of the assumption that system RA may not be needed until later, Sellers may offer resources where FCDS status is expected after IEDD. Sellers can specify any date, and PG&E will consider that date in the offer valuation. Specifically, PG&E will value the offer as energy-only until the specified FCDS date. The PPA includes a contractual obligation to meet that date. If the seller fails to meet that date, the Seller will be subject to damages for up to two years. After two years, failure to meet FCDS is an event of default.~~

~~Project Design Changes: Consistent with the authority granted to it in D.14-11-042, PG&E has modified its PPA to require further clarification to project design characteristics and to require PG&E consent to any changes to project design.~~

~~Renewable Integration Cost Adder: PG&E's LCBF has been modified to include a renewable integration cost adder.~~

~~Time of Deliveries (TOD): TODs in the PPA have been updated to reflect current forecasts of hourly energy and capacity prices.~~

### ~~9.3 Description of the Least-Cost, Best-Fit Criteria and Evaluation Process~~

~~In general, PG&E's LCBF methodology is similar to that approved in PG&E's 2013 RPS Plan. In response to bidder feedback, PG&E has modified Attachment K to its 2014 RPS Solicitation Protocol, which describes PG&E's LCBF methodology, to provide further clarification of how storage offers will be evaluated. PG&E also described other qualitative factors that could be considered during the evaluation process. In accordance with D.14-11-042, PG&E has described its methodology for the interim renewable integration cost~~

~~adder and has updated and clarified the language regarding the curtailment adjustment in Attachment K.~~

~~Please refer to Attachment K in the 2014 RPS Solicitation Protocol, found in Appendix H, for a full description of PG&E's LCBF methodology, including descriptions of each PAV adjustment.~~

~~Finally, if the Commission approves PG&E's pending application to establish a voluntary GTSR, the specific goals for GTSR-dedicated procurement would become another factor to be considered in the "best fit" part of the LCBF evaluation, to the extent that any RPS-like procurement mechanism is used for the GTSR.~~As described in Sections 3 and 7, PG&E is well positioned to meet its RPS targets, under both a 33% RPS target and a 40% RPS scenario, until at least [redacted]. As a result, PG&E proposes that it not issue a 2015 RPS solicitation. PG&E will continue to procure RPS-eligible resources in 2016 through other Commission-mandated programs, such as the ReMAT and RAM Programs.

### 9.1 Proposed TOD Factors

PG&E sets its TOD factors based on expected hourly prices. Given the high penetration of solar generation expected through 2020 and beyond, PG&E forecasts that there will be significant periods of time during the mid-day when net loads are low, resulting in prices that will be low or negative, especially in the spring. This expectation is consistent with forecasts of net load that have been publicized by the CAISO.[70] In addition, given the low mid-day loads, PG&E sees its peak demand (and resulting higher market prices) moving to later in the day. Capacity value has also become significantly less important in the selection process because: (1) market prices for generic capacity are low; and (2) net qualifying capacity using effective load carrying capability is also low. Thus, PG&E would simplify its PPAs and include only a single set of TOD factors to be applied to both energy-only and fully deliverable resources.

PG&E is proposing to update its TOD factors and TOD periods as follows:

Recommendation (New TODs)

- Move peak period from HE16-HE21 to HE17-HE22
- Move mid-day period from HE07-HE15 to HE10-HE16
- Move night period from HE22-HE06 to HE23-HE09
- Move March back to the "Spring" period
- Result: Summer=Jul.-Sep., Winter=Oct.-Feb., Spring=Mar.-Jun.; and Peak=HE17-HE22, Mid-day=HE10-HE16, Night=HE23-HE09

**TABLE 9-1**
**[PROPOSED RPS TIME OF DELIVERY FACTORS]**

| | **Peak** | **Mid-Day** | **Night** |
|---|---|---|---|
| Summer | 1.479 | 0.604 | 1.087 |
| Winter | 1.399 | 0.718 | 1.122 |
| Spring | 1.270 | 0.280 | 1.040 |

70 *See, e.g.*, *CAISO Transmission Plan 2014-2015*, pp. 162-163 (approved March 27, 2015) (available at http://www.caiso.com/Documents/Board-Approved2014-2015TransmissionPlan.pdf).

## 10 Consideration of Price Adjustment Mechanisms

The ACR requires each IOU to "describe how price adjustments (e.g., index to key components, index to Consumer Price Index, price adjustments based on exceeding transmission or other cost caps, etc.) will be considered and potentially incorporated into contracts for RPS-eligible projects with online dates occurring more than 24 months after the contract execution date."[71] ~~The underlying statutory requirement is narrower, focusing solely on price adjustments "associated with the costs of key components."[72]~~

PG&E will consider a non-standard PPA with pricing terms that are indexed, but indexed pricing should be the exception rather than the rule. Customers could benefit from pricing indexed to the cost of key components, such as solar panels or wind turbines, if those prices decrease in the future. Conversely, customers would also face the risk that they will pay more for the energy should prices of those components increase. Asking customers to accept this pricing risk reduces ~~that~~the rate stability that the legislature has found is a benefit of the RPS Program.[73] In order to maximize the RPS Program's benefits to customers, cost risk should generally be borne by developers.

Additionally, indexing greatly complicates offer selection, negotiation and approval. It may be challenging to incorporate contract price adjustment mechanisms into PPA negotiations when there is no clear, well-established and well--defined agreed--upon index. There are many components to the cost of construction of a renewable project, and indexes tied to these various components may move in different directions. The increased complexity inherent in such negotiations is counter to the Commission's expressed desire to standardize and simplify RPS solicitation processes.[74]

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**71** ACR ~~at 17~~, p. 15.

~~**72** Cal. Pub. Util. Code § 399.13(a)(5)(E).~~

**73** *See* Cal. Pub. Util. Code § 399.11(b)(5).

**74** *See* D.11-04-030 ~~at~~, pp. 33-34.

Moreover, Sellers may not have as much incentive to reduce costs if certain cost components are indexed. For example, a price adjustment based on the cost of solar panels (i.e., if panel costs are higher than expected, the price may adjust upward) may not create enough incentive to minimize those costs. This would create a further level of complexity in contract administration and regulatory oversight.

Finally, PG&E does not recommend that PPA prices be linked to the Consumer Price Index ~~(~~(“CPI~~).~~”). The CPI is completely unrelated to the cost of the renewable resource, and is instead linked to increases in prices of oil and natural gas, food, medical care and housing. Indexing prices to unrelated commodities heightens the derivative and speculative character of these types of transactions.

## 11 Economic Curtailment

In D.14-11-042, the Commission approved curtailment terms and conditions for PG&E’s pro forma RPS PPA.[75] In addition, the Commission directed the IOUs to report on observations and issues related to economic curtailment, including reporting to the Procurement Review Group (“PRG”).[76] In May 2015, PG&E made a presentation to its PRG on economic curtailment. This section provides information to the Commission and parties regarding PG&E’s observations and issues related to economic curtailment both for the market generally, and PG&E’s specific scheduling practices for its RPS-eligible resources.

With regard to market conditions generally, the frequency of negative price periods in 2015 has generally increased in the Real-Time Markets, even during the low hydro conditions of 2015. During January through May 2015, negative price intervals in the CAISO Five Minute Market for the North of Path 15 Hub occurred more than 1,800 times (4.2% of 5 minute intervals) compared to 1,100 times (2.5%) during the same period in 2014. Similarly, the ZP26 Hub prices for this period in 2015 were

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[75] D.14-11-042, pp. 43-44.

[76] *Id.*, pp. 42-43.

negative over 4,100 times (9.5%), a substantial increase over the 2014 results of 1,400 times (3.3%). Increased negative price periods have led to increased curtailments of renewable resources that are economically bid. The specific occurrences of negative price periods and overgeneration events are largely unpredictable; [redacted][77] [redacted] PG&E submits bids for these resources based on the resource's opportunity costs, subject to contractual, regulatory, and operational constraints. This also includes the incremental costs of compliance instruments required to comply with the 33% RPS target. PG&E provided more detail concerning its RPS bidding strategy in its proposed 2014 Bundled Procurement Plan ("BPP") which was filed with the Commission in October 2014 and is currently pending at the Commission.[78]

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77 [redacted]

78 *See* PG&E, *Proposed 2014 Bundled Procurement Plan*, R.13-12-010, Appendix K (Bidding and Scheduling Protocol) (October 3, 2014).

[redacted][79][redacted][80] While direct benefits of economic bidding include avoided costs and CAISO market payments associated with negative prices, there can be other important benefits, including potentially avoiding the cost impacts across the rest of PG&E's portfolio due to extreme negative price periods and also potentially enhancing CAISO system reliability by helping to mitigate the occurrences, duration, or severity of negative price periods or overgeneration events.

With regard to longer-term RPS planning and compliance, in order to ensure that RPS procurement need forecasts account for curtailment, PG&E adds curtailment as a risk adjustment within the stochastic model. Under the 33% RPS target, PG&E assumes curtailment [redacted][81] under a 40% RPS scenario, PG&E expects curtailment to increase in line with recent CAISO estimates [redacted].[82] These modeling assumptions will not

[79] [redacted]

[80] [redacted]

[81] [redacted]

[82] [redacted]

necessarily align with the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance. PG&E will continue to observe curtailment events and update its curtailment assumptions as needed. Implementation of these assumptions in PG&E's modeling is discussed in more detail in Section 6.2.3.

Finally, PG&E continues to review its existing portfolio of RPS contracts to determine if additional economic curtailment flexibility may be available to help address the increase in negative pricing events.

## ~~11~~12 Expiring Contracts

The ACR requires PG&E to provide information on contracts expected to expire in the next 10 years.[83] Appendix E lists the projects under contract to PG&E that are expected to expire in the next 10 years. The table includes the following data:

1. PG&E Log Number
2. Project Name
3. Facility Name
4. Contract Expiration Year
5. Contract Capacity (MW)
6. Expected Annual Generation (GWh)
7. Contract Type
8. Resource Type
9. City
10. State
11. Footnotes identifying if PG&E has already secured the expiring volumes through a new PPA

[83] ACR, p. 16.

As indicated in Appendix G, PG&E's RNS calculations assume no re-contracting. Re-contracting is not precluded by this assumption, but rather it reflects that proposed material amendments (i.e., those needed to avoid project failure) or extensions to existing contracts will be evaluated against current offers.

## ~~12~~13 Cost Quantification

This section summarizes results from actual and forecasted RPS generation ~~and~~ costs (including incremental rate impacts~~, notes~~), shows potential increased costs from mandated programs, and identifies the need for a clear cost~~-~~-containment mechanism to address ~~costs of the~~ RPS Program costs. Tables 1~~-~~ through 4 ~~provided~~ in Appendix D provide an annual summary of PG&E's actual and forecasted RPS ~~generation and~~ costs and Page 1 of Appendix D outlines the methodology for calculating the costs and generation.

### ~~12.1~~13.1 RPS Cost Impacts

Appendix D quantifies the cost of RPS-eligible procurement—both historical (2003-~~2013~~2014) and forecast (~~2014-~~2015-2030). From 2003 to 2014, PG&E's annual RPS-eligible procurement and generation costs have continued to increase. Compared to an annual cost of $523 million in 2003, PG&E ~~estimates its annual cost in 2014 to be approximately~~ [redacted]~~. These costs are expected to further increase in the near-term, with forecasted costs reaching approximately $2.8 billion in 2017~~incurred more than [redacted] in procurement costs for RPS-eligible resources in 2014.

~~The costs of the RPS Program are already impacting customer bills and are expected to increase as RPS projects come online in greater quantities in the second RPS compliance period.~~RPS Program costs impact customers' bills. Incremental rate impacts, defined as the annual total cost from RPS-eligible procurement and generation divided by bundled retail sales, effectively serve as an estimate of a system average bundled rate for RPS~~-~~-eligible procurement and generation. While this formula does not provide ~~the reader with~~ an estimate of the renewable "above-market premium" that customers pay relative to a non~~-~~-RPS~~-~~-eligible power alternative, the annual rate impact results in Tables 1 and~~-~~ 2 of Appendix D ~~do~~ illustrate the potential rate of growth in RPS costs and the impact ~~that~~ this growth will have on average rates, all ~~else~~other factors being equal. ~~From 2003 to 2014, the annual~~Annual rate impact of the RPS Program increased from 0.7~~-~~¢/kWh ~~to~~ [redacted] in ~~2013 and~~ [redacted]2003 to an estimated 3.5¢/kWh in ~~2014~~2016, meaning the average rate impact from RPS-eligible procurement has increased more than ~~tripled~~five-fold in approximately ~~ten~~ 12 years. This growth rate is projected to continue increasing through ~~2017~~2020, as the average rate impact is forecasted to increase to [redacted] ~~in 2017. Increasing~~ 3.9¢/kWh. In addition to the increasing RPS costs and incremental rate impacts on customer costs ~~are impacted by both~~resulting from the direct procurement of the renewable resources ~~and the~~, there are incremental indirect transmission and integration costs associated with that procurement.

### ~~12.2~~13.2 Procurement Expenditure ~~Limitations~~Limit

~~The only reasonable reading of SB 2 (1x) requires~~Section 399.15(f) provides that the Commission waive the RPS obligations of an electrical corporation once it meets the cost containment limitation, provided that additional resources cannot be procured without exceeding "a de minimis increase in rates."[84] ~~PG&E is currently working with the Commission and other stakeholders to finalize and implement the PEL. As discussed in greater detail in Section 5, PG&E makes every effort to procure least-cost and best-fit renewable resources in an effort to manage the cost impact that RPS procurement will have on customers. As such, PG&E believes the procurement expenditure limitation should be clear, stable, and meaningful in order to~~ The methodology for the PEL, the Commission's cost containment mechanism, is still under development. As discussed in Section 2.2, PG&E looks forward to the Commission finalizing the PEL methodology and implementing it, to ensure that customers are

[84] ~~Cal. Pub. Util. Code § 399.15(f).~~

adequately protected and promote regulatory certainty and support procurement planning.

### ~~12.3~~13.3 Cost Impacts Due to Mandated Programs[85]

As PG&E makes progress ~~to~~toward achieving the RPS goal of 33%, the ~~impact~~cost impacts of mandated procurement programs ~~focused~~that focus on particular technologies or project size ~~will become more significant as they comprise~~increase over time, and procurement from those programs increasingly comprises a larger share of PG&E's incremental procurement goals. ~~Such~~ In general, mandated procurement programs do not optimize RPS costs for customers ~~and may not serve as an~~ because they restrict flexibility and optionality to achieve emissions reductions by mandating procurement through a less efficient ~~procurement mechanism. PG&E supports a technology neutral procurement process, where all technologies can compete as to which projects the best value to customers at the lowest cost. In general, mandates increase prices and constrain the efficiency of meeting a given goal.~~and more costly manner. For instance, research ~~on the enhanced efficiency of~~ shows that market-based mechanisms, like cap-and-trade ~~compared to~~, that allow multiple and flexible emissions reduction options, have lower costs than mandatory mechanisms like technology targets ~~is well established.[86] That research shows that having flexibility and several options to achieve the goal of emissions reductions is less costly than requiring~~that allow only a

~~[85] Mandated programs within the RPS program include the PV Program, the Renewable Auction Mechanism (RAM) for projects 3-20 MW, the Renewable Market Adjusting Tariff (ReMAT) for projects up to 3 MW, the CHP program, and the bio-energy program required by SB 1122.~~

~~[86] *See*, e.g., "Cost-Effectiveness of Renewable Electricity Policies" from Palmer and Burtraw (2005) (available at http://www.rff.org/Documents/RFF-DP-05-01.pdf); "The Cost of Climate Policy in the U.S." from Sergey Paltsev et. al. (2009) (available at http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.177.6721&rep=rep1&type=pdf); "Modeling Policies to Promote Renewable and Low-Carbon Sources of Electricity" from Palmer, Sweeney, and Allaire (2010) (available at http://www.rff.org/RFF/Documents/RFF-BCK-Palmeretal%20-LowCarbonElectricity-REV.pdf).~~

subset of those options.[87] Studies have also shown that renewable electricity mandates increase prices and costs,[88] and procurement mandates within California's RPS decrease efficiency in the same way.

Mandates restrict the choices ~~complying entities (IOUs in this case) have~~ to meet the RPS targets, removing potentially less expensive options from the market. This can increase prices in two ways: first, by disqualifying those less expensive participants and second, ~~creating a less robust market in which participants compete.~~~~[89]~~by creating a less robust market for participants to compete.[90] PG&E's customers also pay incremental costs due to the administrative costs associated with managing separate solicitations for mandated resources. In addition, smaller project sizes for mandated programs create a greater number of projects which, in turn, affect interconnection and transmission availability and costs. Finally, mandated programs do not enable PG&E to procure the technology, size, vintage, location and other attributes that would best fit its portfolio. As a result, PG&E's costs for managing its total generation and portfolio increase. For these reasons, PG&E supports a technology

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87 *See*, *e.g.*, Palmer and Burtraw, "Cost-Effectiveness of Renewable Electricity Policies" (2005) (available at http://www.rff.org/Documents/RFF-DP-05-01.pdf); Sergey Paltsev et. al, "The Cost of Climate Policy in the U.S." (2009) (available at http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.177.6721&rep=rep1&type=pdf); Palmer, Sweeney, and Allaire, "Modeling Policies to Promote Renewable and Low-Carbon Sources of Electricity" (2010) (available at http://www.rff.org/RFF/Documents/RFF-BCK-Palmeretal%20-LowCarbonElectricity-REV.pdf).

88 *See*, *e.g.*, Institute for Energy Research, "Energy Regulation in the States: A Wake-up Call" ~~from the Institute for Energy Research~~ (available at http://www.instituteforenergyresearch.org/pdf/statereport.pdf); Manhattan Institute, "The High Cost of Renewable Electricity Mandates" ~~from the Manhattan Institute~~ (available at http://www.manhattan-institute.org/html/eper_10.htm).

~~89 *See* "Combining Policies for Renewable Energy: Is the Whole Less Than the Sum of Its Parts?" from Fischer and Preonas (2010) (available at http://www.rff.org/Documents/Fischer_Preonas_IRERE_2010.pdf).~~

90 *See*, Fischer and Preonas, "Combining Policies for Renewable Energy: Is the Whole Less Than the Sum of Its Parts?" (2010) (available at http://www.rff.org/Documents/Fischer_Preonas_IRERE_2010.pdf).

neutral procurement process, in which all technologies can compete to demonstrate which projects provide the best value to customers at the lowest cost.

~~The first way mandated programs can reduce efficiency and increase overall cost for PG&E's customers is by requiring procurement of higher-cost resources under technology specific mandates. For example, the SB 1122 small-scale bioenergy feed-in tariff program requires PG&E to procure 111 MW of bioenergy projects. In an October 31, 2013 report produced by Black & Veatch for the Commission, the cost of generation will vary considerably among bioenergy technologies, but is likely to average $130/megawatt-hour (MWh)-$200/MWh for a blended rate, with some nascent bioenergy technologies predicted to cost up to $346/MWh.[91] To put this in perspective, customers may pay a premium for these bioenergy projects of approximately $60-$130/MWh compared to alternative renewable projects of similar size that have been executed through the existing FIT program.~~

~~The second way mandates increase costs is by creating a less robust market in which participants can compete. Limited eligibility of participants in these mandate programs reduces market liquidity and makes participants in that market segment less subject to the competitive pressures that have driven increasing efficiency in the broader, unconstrained market. Procurement mandates are a form of market quota which distort market-clearing prices by disqualifying otherwise eligible supply and result in thinner competition in the remaining supply.~~

~~Additionally, PG&E's customers must pay incremental costs due to the specific mandate that are not captured in the project price. Administrative costs associated with managing the separate solicitations and project administration~~

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~~[91] Black & Veatch. *Final Consultant Report Small-Scale Bioenergy: Resource Potential, Costs and Feed-in Tariff Implementation Assessment,* prepared for California Public Utilities Commission, October 31, 2013, pp. 1-1 and 1-5.~~

~~raise customer costs. Smaller project sizes create a greater number of projects which in turn affect interconnection and transmission availability and costs. Lastly, mandated programs do not enable PG&E to procure the technology, size, vintage, location and other attributes that would best fit its portfolio. As a result, PG&E's costs for managing its total generation and portfolio increase.~~

**~~Expiring Contracts~~**

~~The ACR requires PG&E to provide information on contracts expected to expire in the next 10 years. This information is intended to build upon analysis previously completed by Energy Division.~~[92] ~~Table 1 of Appendix E lists the projects under contract to PG&E and expected to expire in the next 10 years. The table includes the following data:~~

1) ~~Project Name;~~
2) ~~Name of Facility~~
3) ~~Contract Expiration Year;~~
4) ~~Contract Type;~~
5) ~~Contract Capacity (MW);~~
6) ~~Expected Annual Generation (GWh);~~[93]
7) ~~Technology~~
8) ~~City;~~
9) ~~State; and~~
10) ~~Footnotes identifying if PG&E has already secured the expiring volumes through a new PPA.~~

~~The table is sorted by expiration year.~~

[92] ~~ACR at 21.~~

[93] ~~Some QF facilities, though under active contracts, have not and are not expected to deliver power to PG&E in the future. In these instances, PG&E has entered a zero value for the contract's Expected Annual Generation.~~

~~As indicated in Appendix G, PG&E's RNS calculations assume no re-contracting. Re-contracting is not precluded by this assumption, but rather it reflects that proposed material amendments (i.e., those needed to avoid project failure) or extensions to existing contracts will be evaluated against current offers. PG&E will encourage generators with contracts expiring beyond the next few years to submit offers for extensions that will provide bankable products under the Commission's RPS compliance rules in upcoming solicitations, including the 2014 RPS Solicitation, because this may be their window of opportunity to secure long-term contracts. Existing RPS-eligible contracts that are expiring before 2020 face a different challenge. In order to be competitive, these near-term expiring contracts will need to offer extensions or new contracts at discounted prices because of the poor fit of near-term deliveries with PG&E's RPS need, or they will need to find other off-takers in the intermediate-term.~~

## ~~13~~14 Imperial Valley

For the ~~IOU's 2013~~IOUs' 2014 RPS solicitations, the Commission did not specifically require any remedial measures to bolster procurement from Imperial Valley projects but required continued monitoring of IOUs' renewable procurement activities in the Imperial Valley area. ~~The results of the 2013 RPS Solicitation from Imperial Valley projects were robust~~[94] Even without ~~special or~~ remedial measures~~. Given the robustness of the response from Imperial Valley projects in both the 2012 and 2013 RPS solicitations, PG&E does not see a need to specifically address the region in its 2014 RPS Plan nor include any further special remedial measures. With regard to the results of Imperial Valley projects~~ in PG&E's ~~2013~~2014 RPS Solicitation, the Independent Evaluator monitoring that solicitation found ~~as follows~~that:

> Overall, the response of ~~the developer community~~developers to propose Imperial Valley projects was robust ~~(though less so than in prior years)~~ and PG&E's selection of Imperial Valley Offers was representative of that response. Arroyo perceives no evidence that PG&E failed in any way to perform outreach to ~~generation~~ developers ~~and owners~~ active in the

[94] D.14-11-042, pp. 15-16.

Imperial Valley or that there was any structural impediment in the RFO process that ~~materially~~ hindered the selection of competitively priced Offers for projects in the Imperial Valley.[95]

Given the robustness of the response from Imperial Valley projects in the 2014 RPS solicitation, as well as the 2013 RPS solicitation, and given the fact that PG&E is not planning on conducting a 2015 RPS solicitation, there does not appear to be a need to adopt any special remedial measures for the Imperial Valley as a part of the RPS Plan.

The ACR also directs the IOUs to report on any CPUC-approved RPS PPA for projects in the Imperial Valley that are under development, and any RPS projects in the Imperial Valley that have recently achieved commercial operation.[96] PG&E has one PPA under contract in the Imperial Valley. That project is in development. Commercial operation is expected in 2016, with deliveries under the PPA beginning in 2020.

## ~~14~~15 Important Changes to Plans Noted

This section describes the most significant changes between PG&E's ~~2013 RPS Plan and its~~ 2014 RPS Plan~~. A~~ and its 2015 RPS Plan. A complete redline of the draft 2015 RPS Plan ~~document~~ against PG&E's ~~2013~~2014 RPS Plan ~~was~~is included ~~at Appendices~~ as Appendix A ~~and I of the June 4, 2014 Draft RPS Plan filed in Rulemaking (R.) 11-05-005. PG&E also filed an update to its draft RPS Plan on August 20, 2014 and included a redline in that filing showing the additional~~. This section identifies and summarizes the key changes~~. Appendices A and I to this Final~~ and differences between the 2014 RPS Plan and the proposed 2015 RPS Plan ~~show modifications between the June 4, 2014 Draft RPS Plan and this Final RPS Plan. Pursuant to D.14-11-042, PG&E is submitting concurrently with this Final RPS Plan a Tier 1 Advice Letter that describes and seeks Commission approval of the additional~~

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95 PG&E, *Advice Letter ~~4398~~4632-E*, ~~April 21, 2014~~p. 40, Section 2 (IE Report) ~~at 50.~~(May 7, 2015).

96 ACR, p. 19.

~~changes since the Commission's conditional approval~~. Specifically, the table below provides a list of ~~the Draft RPS Plan. Finally, Section 9 of this Plan summarizes significant changes made to the 2014 RPS Solicitation Protocol.~~

~~**14.1 Summary of the Important Changes Between the 2013 and 2014 RPS Procurement**~~key differences between the two RPS Plans:

| Reference | Area of Change | Summary of Change | Justification ~~of Change~~ |
|---|---|---|---|
| Section 1 | Section format and structure | ~~PG&E includes a "Highlights" section summarizing the plan.~~Remove "Executive Summary" from Introduction. | Ease of document flow. |
| ~~Section 2~~Entire RPS Plan | ~~Section format and structure~~ Consideration of a Higher RPS Requirement | ~~Changed order of introduction to better capture the contents of the plan.~~Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario. | ~~Ease of document flow.~~ACR at pp.5-6. |
| Section ~~3~~2.1 | ~~Assessment of RPS Portfolio Supplies and Demand~~Commission Implementation of SB 2 (1x) | ~~Updates PG&E's supply and demand for renewables to maintain compliance with current legislation.~~Include discussion of D.14-12-023, setting RPS compliance and enforcement rules under SB 2 (1X). | ~~ACR, dated March 26, 2014. See Section 3 for further details.~~ACR at p. 4. |
| Section 3.2.2 | Impact of Green Tariff Shared Renewable Program | Include discussion of impact of Green Tariff Shared Renewable Program on RPS position. | D.14-11-042; D.15-01-051. |

| Reference | Area of Change | Summary of Change | Justification ~~of Change~~ |
|---|---|---|---|
| Section 3.4 | ~~Assessment of RPS Portfolio Supplies and Demand~~Anticipated Renewable Energy Technologies and Alignment of Portfolio With Expected Load Curves and Durations | ~~Per the requirements of the ACR, PG&E moved "Lessons Learned" in 2012 Plan to Section 3 and updated.~~ Include discussion of integration cost adder as part of LCBF bid evaluation methodology. | ACR ~~dated March 26, 2014~~at p.15. |
| Section ~~4 & Appendix B~~3.5 | ~~Project Development Status Report~~RPS Portfolio Diversity | ~~Provides an update on the development of RPS resources currently under development.~~Include discussion of efforts to increase portfolio diversity. | ~~ACR, dated March 26, 2014.See Section 4 and Appendix B for further details.~~ACR at p.10. |
| Section 5.4 | ~~Potential Compliance Delays~~Curtailment of RPS Generating Resources | ~~Updates PG&E's review~~Include discussion of ~~project development obstacles that could lead to~~economic curtailment as a potential compliance ~~delays~~delay. | ~~ACR, dated March 26, 2014. See Section 5 for further details.~~ACR at p.16. |
| Section ~~6~~11 | ~~Risk Assessment~~Economic Curtailment | ~~Updates PG&E's demand-side and supply-side risks that impact the renewables portfolio.~~ Include discussion of economic curtailment. | ~~ACR, dated March 26, 2014. See Section 6 for further details.~~ACR at p.16. |
| ~~Section 6~~ | ~~Risk Assessment~~ | ~~PG&E describes the methodology for its deterministic and stochastic models.~~ | ~~To provide greater clarity regarding portfolio optimization strategy and tools.~~ |

| Reference | Area of Change | Summary of Change | Justification ~~of Change~~ |
|---|---|---|---|
| ~~Section 7,~~ Appendix C.~~1-C.2, & Appendix F~~1b | ~~Quantitative Information~~Renewable Net Short Calculations – 40% RPS Scenario | ~~Provides the quantitative results of the deterministic and stochastic models.~~ Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario. | ~~ACR, dated March 26, 2014. See Section 7, Appendices C.1 and C.2, and Appendix F for further details.~~ACR at pp.5-6. |
| ~~Section 7~~Appendix C.2b | ~~Quantitative Information~~Alternate Renewable Net Short Calculations – 40% RPS Scenario | ~~Updates the results from the methodology used to produce PG&E's net short calculation and describes the implications of that calculation for PG&E's RPS compliance outlook and RPS procurement strategy.~~Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario. | ~~ACR, dated March 26, 2014. See Section 7, Appendices C.1 and C.2, and Appendix F for further details.~~ACR at pp.5-6. |
| ~~Sections 6, 7 and 8~~ | ~~RPS Portfolio Optimization Strategy~~ | ~~Consideration of Portfolio Optimization from 2013 Plan is moved to Section 6, 7, and 8.~~ | ~~ACR, dated March 26, 2014 did not require a separate Portfolio Optimization Section.~~ |

| Reference | Area of Change | Summary of Change | Justification ~~of Change~~ |
|---|---|---|---|
| ~~Section 8~~Appendix F.2b | ~~Margins of Procurement~~Project Failure Variability – 40% RPS Scenario | ~~Updates how PG&E's minimum and voluntary margins of procurement methodologies were incorporated into PG&E's quantitative analysis of its RPS need and into the development of its 2014 RPS procurement goal.~~Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario. | ~~ACR, dated March 26, 2014.~~ ACR at pp.5-6. |
| ~~Section 9~~Appendix F.3b | ~~Bid Selection Protocol~~RPS Generation Variability – 40% RPS Scenario | ~~Discusses PG&E's 2014 procurement goals and the relationship between RPS needs and RPS goals. Summarizes major changes to 2014 Protocol and modifications to commercial terms in the 2014 RPS Form PPA.~~Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario. | ~~ACR, dated March 26, 2014. See the Final Protocol for further details.~~ACR at pp.5-6. |
| ~~Section 11 & Appendix D~~ | ~~Summary of Cost Quantification Results~~ | ~~Updates the summary of PG&E's historic and forecasted RPS cost and rate information.~~ | ~~ACR, dated March 26, 2014.~~ |

| Reference | Area of Change | Summary of Change | Justification ~~of Change~~ |
|---|---|---|---|
| ~~Section 15~~Appendix F.4b | ~~Commission-Approved RPS Programs~~RPS Deliveries Variability – 40% RPS Scenario | ~~Moved and updated status of Commission-approved RPS Programs from RPS Plan introduction to Section 15.~~Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario. | ~~Ease of document flow.~~ACR at pp.5-6. |
| Appendix ~~C~~F.5b | ~~Renewable Net Short calculation~~RPS Target Variability – 40% RPS Scenario | ~~Updates the RNS tables to align with methodology outlined by the CPUC.~~Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario. | ~~ALJ Ruling on RNS, May 21, 2014.~~<br>~~Clarifying requirements and transparency.~~ACR at pp.5-6. |
| ~~Appendix J~~ | ~~RNS Ruling Questions~~ | ~~Added a new appendix to provide PG&E's responses to the eleven questions posed by the May 21, 2014 ALJ Ruling on the RNS methodology.~~ | ~~ALJ Ruling on RNS, May 21, 2014.~~ |

# ~~15 Other RPS Planning Considerations and Issues~~

## ~~15.1 Contract Amendments~~

~~In this section, PG&E describes the process for regulatory approval of amendments to previously executed and approved RPS contracts. Pursuant to D.14-11-042, some of the contract amendments described in this section will be subject to the Standards of Review adopted in that decision.~~

~~The Tier 1 Advice Letter process is used when PG&E exercises a contract option under a previously approved RPS PPA, such as additional, incremental renewables procurement at the PPA approved price. The Commission may also direct PG&E to make specific filings by a Tier 1 Advice Letter.~~

~~The Tier 2 Advice Letter process is used for amendments other than those handled through routine contract administration and amendments that do not materially decrease the value of the PPA or increase ratepayer costs. The Commission may also direct PG&E to make specific filings by a Tier 2 Advice Letter.~~

~~The Tier 3 Advice Letter process is used for amendments that would increase PPA costs, address issues explicitly reserved by the Commission for further deliberation, or materially decrease the value of a PPA. In general, PG&E will consider price adjustments where the revised price and terms of the contract enhance the value of the deal for PG&E's customers, taking into account qualitative RPS goals. PG&E will continue to submit a Tier 3 advice letter for any amendments for which additional Commission approval is required or when PG&E feels it is warranted.~~

~~Routine contract changes are managed by PG&E and are subsequently reported in the Quarterly Compliance Report (QCR). Approval of these changes is requested in the annual Energy Resource Recovery Account proceeding that follows the reporting of the changes in the QCR.~~

## ~~15.2 Status of Commission-Approved RPS Procurement Programs~~

~~PG&E participates in a number of Commission-approved RPS procurement programs. These programs include the PV Program, the RAM Program, the FIT Program, and the QF/CHP Settlement. Below is an update on the status of these programs.~~

### ~~15.2.1 Update on Photovoltaic Program~~

~~In D.10-04-052, the Commission approved PG&E's PV Program – a five-year program designed to promote the development of smaller-sized PV facilities in PG&E's service territory, with a focus on ground-mounted projects in the one to 20 megawatt range. The Commission authorized PG&E to own and operate 250 MW of PV~~

~~facilities in the one to 20 MW range and to enter into long-term PPAs with 20 year terms for 250 MW of similar facilities. In December 2012, PG&E filed advice letters with the Commission, proposing to terminate Program Years 4 and 5 of the UOG portion of the PV Program and Years 3, 4 and 5 of the PPA portion of the Program, and instead to utilize the RAM procurement process to procure those remaining procurement volumes in annual solicitations to be held in 2014, 2015 and 2016. On February 7, 2014 the Commission issued a disposition letter rejecting PG&E's PV advice letters, stating that the request should be submitted in the form of a request for modification. On February 26, 2014 PG&E filed a Petition for Modification (PFM) requesting to terminate the PV Program and a separate PFM requesting to modify the RAM Decision process to procure the remaining PV Program volumes using RAM solicitation processes. The Commission approved these requests in part in Decisions 14-11-042 and 14-11-026. Specifically, D.14-11-026 terminated the PV Program after program year 3. PG&E is in the process of conducting its third and final PV PPA Program solicitation.~~

**~~15.2.2 Update on RAM Program~~**

~~In D.10-12-048, the Commission approved the RAM Program to facilitate the development of smaller renewable projects. D.10-12-048 requires the IOUs to conduct a total of four solicitations, two per program year for two years. PG&E issued its first RAM solicitation in November 2011, and executed four contracts for a total of 63 MW. PG&E issued its second RAM solicitation, which closed on May 31, 2012, pursuant to the schedule adopted by the Commission in Resolution E-4414. Under RAM 2, PG&E executed eight PPAs for a total of 140 MW. Subsequent to contract execution, one of the Sellers terminated a PPA for a 20 MW PV plant. PG&E added the 20 MW to the~~

~~third RAM. As a result of the RAM 3 solicitation, which was issued in November 2012, PG&E executed six PPAs for a total of 115 MW.~~

~~On May 9, 2013, the CPUC issued a Resolution that changed the RAM Program in two key ways: (1) modified the capacity allocation requirements for the RAM 4; and (2) authorized a RAM 5 to close no later than June 27, 2014 and mandated the IOUs to reserve one-third of their remaining previously authorized, yet unsubscribed, RAM capacity for RAM 5. PG&E executed 60.3 MW under the RAM 4 solicitation, which was issued on May 28, 2013. PG&E has closed its RAM 5 solicitation and expects Commission approval of the resulting contracts prior to the end of 2014.~~

~~In D.14-11-042, the Commission mandated an additional auction to close in June 2015. Additionally, D.14-11-042 transferred one-half of the remaining authorized capacity in PG&E's PV Program into RAM 6 and the remaining one-half of the remaining PV Program capacity to additional solicitations to be held in 2016 and 2017. Finally, D.14-11-042 authorized PG&E and the other large IOUs to include RAM-like components within their annual RPS solicitations, beginning in 2015.~~

**~~15.2.3 Update on FIT Program~~**

~~In D.07-07-027, the Commission implemented AB 1969, which added Section 399.20 to the Pub. Util. Code. D.07-07-027 established a FIT Program for RPS-eligible projects that are 1.5 MW and less. The Commission subsequently approved PG&E's Electric Schedules E-SRG and E-PWF that provide a tariff and form contract for eligible facilities. Since 2007, the Legislature adopted several amendments to the Section 399.20 renewable FIT Program. For example, SB 32 expanded the FIT Program to eligible renewable generators that are 3 MW and less. The Commission issued three decisions addressing the~~

~~amendments to Section 399.20 enacted by SB 380, SB 32, and SB 2 1X: D.12-05-035; D.13-01-041 modifying D.12-05-035; and D.13-05-034.~~

~~D.12-05-035 adopted new program requirements applicable to expanded FIT Program, including ReMAT, but did not fully implement a revised FIT Program. The Commission deferred consideration of the terms and conditions of a joint IOU PPA and tariffs applicable to expanded FIT Program to a subsequent decision.~~

~~On May 23, 2013, the Commission adopted D.13-05-034, which addressed the joint IOU PPA and tariff terms applicable to the expanded FIT Program. Pursuant to D.13-05-034, PG&E filed a Tier 2 advice letter for approval of the PPA and replacement tariffs on June 24, 2013. The replacement ReMAT tariff became effective on July 24, 2013 at which time PG&E no longer accepted contracts under the AB 1969 program. Under the timelines adopted by D.13-05-034, PG&E opened the ReMAT program for applicants to submit their Program Participation Requests. The first program period commenced on November 1, 2013. To date, PG&E has executed fifteen (15) PPAs for a total of 18.109 MW. In Program Period 1, PG&E executed ten (10) PPAs totaling 8.844 MW for solar PV, small hydro and landfill gas projects at the starting price of $89.23/MWh. In Program Period 2, PG&E executed three (3) PPAs totaling 4.745 MW for solar PV and small hydro projects at $85.23 and $89.23, respectively. In Program Period 3, PG&E executed two (2) PPAs totaling 4.52 MW for solar PV projects at $77.23. D.13-05-034 does not address the recently effective amendments to Section 399.20 enacted by SB 1122. Pursuant to D.13-05-034 and the January 2013 scoping plan in R.11-05-005, the Commission will address SB 1122 and modify the FIT Program consistent with the legislation in a subsequent decision.~~

~~**15.2.4 QF/CHP Settlement**~~

~~In D.10-12-035, the Commission approved the QF and CHP Settlement. One element of the QF/CHP Program established by the QF/CHP Settlement is a form PPA for QFs that are 20 MW and under. This form QF PPA is available to both RPS-eligible and non-RPS-eligible QFs at terms of maximum seven years for existing facilities and 12 years for new facilities. The QF/CHP Settlement became effective on November 23, 2011, and provides another opportunity for RPS-eligible QFs that satisfy the program criteria to contract with PG&E. RPS-eligible megawatts procured under this program will be counted toward PG&E's RPS compliance requirements, to the extent allowed by the Commission's RPS compliance rules.~~

## 16 Safety Considerations

PG&E is committed to providing safe utility (electric and gas) service to its customers. As part of this commitment, PG&E reviews its operations, including energy procurement, to identify and mitigate, to the extent possible, potential safety risks to the public and PG&E's workforce and its contractors. Because PG&E's role in ensuring the safe construction and operation of RPS-eligible generation facilities depends upon whether PG&E is the owner of the generation or is simply the contractual purchaser of RPS-eligible products (e.g., energy and RECs), this section is divided into separate discussions addressing each of these situations.

### 16.1 ~~Safety Considerations Related to the~~ Development and Operation of PG&E-Owned, RPS-~~-~~Eligible~~, PG&E-Owned~~ Generation

While PG&E is not proposing as part of its ~~2014~~2015 RPS Plan to develop additional utility-owned renewable facilities, its existing RPS portfolio contains a ~~significant~~ number of such facilities. To the extent that PG&E builds, operates, maintains, and decommissions its own RPS-eligible generation facilities, PG&E follows its internal standard protocols and practices to ensure public, workplace, and contractor safety. For example, PG&E's Employee Code of Conduct describes the safety of the public, employees and contractors as PG&E's highest priority.[97] PG&E's commitment to a safety-first culture is reinforced with its Safety Principles, PG&E's Safety

[97] *See* PG&E~~-~~, "Employee Code of Conduct~~,~~" (August 2013~~,~~) (available at http://www.pgecorp.com/aboutus/corp_gov/coce/employee_conduct_standards.shtml~~.~~). *See* ~~*also*~~, *e.g.*, PG&~~E's~~ E, "Contractor, Consultant, and Supplier Code of Conduct ~~at~~," p. 3 (available at http://www.pgecorp.com/aboutus/ethics_compliance/con_con_ven~~/~~/)~~)~~.

Commitment, Personal Safety Commitment and Keys to Life.[98] These tools were developed in collaboration with PG&E employees, leaders, and union leadership and are intended to provide clarity~~,~~ and support~~ and confidence~~ as employees strive to take personal ownership of safety at PG&E. Additionally, PG&E seeks all applicable regulatory approvals from governmental authorities with jurisdiction to enforce laws related to worker health and safety, impacts to the environment, and public health and welfare.

As more fully detailed in PG&E’s testimony in its General Rate Case ~~(~~(“GRC~~),~~”),[99] the top priority of PG&E’s ~~Energy~~Electric Supply organization is public and employee safety, and its goal is to safely operate and maintain its generation facilities. In general, PG&E ensures safety in the development and operation of its RPS~~-~~-eligible ~~(e.g., hydropower, PV, and fuel cell)~~ facilities in the same manner as it does for its other UOG facilities. This includes the use of recognized best practices in the industry.

PG&E operates each of its generation facilities in compliance with all local, state and federal permit and operating requirements such as state and federal Occupational Safety and Health Administration ~~(~~(“OSHA~~)~~”) and the California Public Utilities Commission’s General Order 167. PG&E does this by using internal controls to help manage the operations and maintenance of its generation facilities, including: (1) guidance documents; (2) operations reviews; (3) an incident reporting process; (4) a corrective action program; (5) an outage planning and scheduling process; (6) a project management process; and (7) a design change process.

PG&E’s Environmental Services organization also provides direct support to the generation facilities, with a focus on regulatory compliance. Environmental consultants

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98 *See* PG&E~~-~~, “Employee Code of Conduct~~,~~” *supra* (describing the Safety Principles, Safety Commitment, Personal Safety Commitment and Keys to Life).

99 *See* PG&E, *Prepared Testimony*~~ in its~~, *2014 GRC, Application 12-11-009*, Exhibit (PG&E-6), Energy Supply, ~~at~~pp. 1-11, 2-17, 2-44, 2-66, 4-13 (available at ~~https://www.pge.com/regulation/GRC2014-Ph-I/Testimony/PGE/2012/GRC2014-Ph-I_Test_PGE_20121115_254325.pdf).~~http://www.pge.com/regulation/).

are ~~located at~~assigned to each of the ~~fossil fuel~~ generating ~~stations~~facilities and support the facility staff.

With regard to employee safety, Power Generation employees develop a safety action plan each year. This action plan focuses on various items such as clearance processes and electrical safety, switching and grounding observations, training and qualifications, expanding the use of Job Safety Analysis tools, peer~~-~~-to~~-~~-peer recognition, near~~-~~-hit reporting, industrial ergonomics, and human performance.

Employees also participate in an employee led Driver Awareness Team established for the sole purpose of improving driving. An annual motor vehicle incident ~~(~~(“MVI~~)~~”) Action Plan is developed and implemented each year. This action plan focuses on vehicle safety culture and implements the Companywide motor vehicle safety initiatives in addition to specific tools such as peer driving reviews and 1 800~~-~~-phone number analysis to reduce MVIs.

The day-to-day safety work in the operation of PG&E’s ~~hydropower~~generation facilities consists of base activities such as:

- Industrial and office ergonomics training/evaluations
- Illness and injury prevention
- Health and wellness training
- Regulatory mandated training
- Training and re certification for the safety staff
- Culture based safety process
- Asbestos and lead awareness training
- Safety at Heights Program
- Safe driving training
- First responder training
- Preparation of safety tailboards and department safety procedures
- Proper use of personal protective equipment

- Incident investigations and communicating lessons learned
- Employee injury case management
- Safety performance recognition
- Public safety awareness

The safety focus of PG&E's hydropower operations includes the safety of the public at, around, and/or downstream of PG&E's facilities; the safety of our personnel at and/or traveling to PG&E's hydro facilities; and the protection of personal property potentially affected by PG&E's actions or operations. With regard to public safety, PG&E is developing and implementing a comprehensive public safety program that includes: (1) public education, outreach and partnership with key agencies; (2) improved warning and hazard signage at hydro facilities; (3) enhanced emergency response preparedness, training, drills and coordination with emergency response organizations; and (4) safer access to hydro facilities and lands, including trail access, physical barriers, and canal escape routes.

PG&E has also funded specific hydro-related projects that correct potential public and employee safety hazards, such as Arc Flash Hazards, inadequate ground grids, and waterway, penstock, and other facility safety condition improvements.

PG&E will never be satisfied in its safety performance until there is never an injury to any of its employees, contractors, or members of the public. Over the past several years, PG&E's Power Generation organization has been creating a culture of safety first with strong leadership expectations and an increasingly engaged workforce. Fundamental to a strong safety culture is a leadership team that believes every job can be performed safely and seeks to eliminate barriers to safe operations. Equally important is the establishment of an empowered grass roots safety team that can act to encourage safe work practices among peers. Power Generation's grass roots team is led by bargaining unit employees from across the organization who work to include safety best practices in all the work they do. These employees are closest to the day-

-to--day work of providing safe, reliable, and affordable energy for PG&E's customers and are best positioned to implement change that can improve safety- performance.

### 16.2 ~~Safety Considerations Related to the~~ Development and Operation of Third-Party-–Owned, RPS--Eligible Generation

The vast majority of PG&E's procurement of products to meet RPS requirements has been from third--party generation developers. In these cases, local, state and federal agencies that have review and approval authority over the generation facilities are charged with enforcing safety, environmental and other regulations for the Project, including decommissioning. ~~Section 3.9(a) (iii) of PG&E's Draft 2013 RPS Form PPA, which is Attachment H1 to the 2014 Draft RPS Solicitation Protocol at Appendix H, requires the Seller to "[a]cquire all permits and other approvals necessary for the construction, operation and maintenance of the Project."~~While this authority has not changed, PG&E intends to add additional contract provisions to its contract forms to reinforce the developer's obligations to operate in accordance with all applicable safety laws, rules and regulations as well as Prudent Electrical Practices, which are the continuously evolving industry standards for operations of similar electric generation facilities. Additionally, the new provisions will seek to implement lessons learned and instill a continuous improvement safety culture that mirrors PG&E's approach to safety.

~~Additionally, Section 3.5 of the 2014 RPS Form PPA identifies several general operational, CAISO and Western Electricity Coordinating Council standards and reliability standards with which the generator seller must comply.~~[100] ~~Specifically, the Draft 2014 Form RPS PPA requires that a generating facility under contract to PG&E "be operated and maintained in a~~

[100] ~~Specifically, Section 3.5(b) requires that, "each Party shall perform all generation… in compliance with all applicable (i) operating policies, criteria, rules, guidelines, tariffs and protocols of the CAISO, (ii) WECC scheduling practices and (iii) Good Utility Practices." Section 1.138 further defines "Good Utility Practices" consistent with the definition provided in the CAISO Tariff. Section 3.5(c) requires the Seller to "abide by . . . CPUC G.O. No. 167, 'Enforcement of Maintenance and Operation Standards for Electric Generating Facilities'…"~~

~~*safe*, reliable and efficient manner *that reasonably protects the public health and safety of California residents, businesses, employees, and the community.*"[101] Additionally, a generator has an obligation under the Form RPS PPA to employ "the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, *safety*, and expedition…."[102]~~

Specifically, the safety language that PG&E is developing builds upon the former standard of Good Utility Practices to a new standard of Prudent Utility Practices, which includes greater detail on the types of activities covered by this standard, including but not limited to safeguards, equipment, personnel training, and control systems.

Safety is also addressed as part of a generator's interconnection process, which requires testing for safety and reliability of the interconnected generation. PG&E's general practice is to declare that a facility under contract has commenced deliveries under the PPA only after the interconnecting utility and the CAISO have concluded such testing and given permission to commence commercial operations.

PG&E receives monthly progress reports from generators who are developing new RPS-~~-~~eligible resources where the output will be sold to PG&E. As part of this progress report, generators are required to provide the status of construction activities, including OSHA recordables and work stoppage information. Additionally, the new

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~~101 Draft 2014 RPS Form PPA, Sections 3.5(c) (incorporating provisions of G.O. 167); G.O 167, Appendix A, General Duty Standard 1 (available at http://docs.cpuc.ca.gov/PUBLISHED/GENERAL_ORDER/108114.htm) (emphasis added).~~

~~102 Draft 2014 RPS Form PPA, Sections 3.5(b) and 1.33 (incorporating CAISO Tariff); CAISO, Fifth Replacement FERC Electric Tariff (Open Access Transmission Tariff), Appendix A, PDF pages 827-828 (available at http://www.caiso.com/Documents/CombinedPDFDocument-FifthReplacementCAISOTariff.pdf) (emphasis added).~~

contract provisions would require reporting of Serious Incidents and Exigent Circumstances shortly after they occur. If the generator has repeated safety violations or challenges, the generator could be at greater risk of failing to meet a key project development milestone or failing to meet a material obligation set forth in the PPA.

The decommissioning of a third--party generation project is not addressed in the ~~RPS Form PPA, and therefore a third-party generator generally has no obligation to PG&E to decommission its project once the PPA has terminated.~~form contract. In many cases, it may be expected that a third-party generator may continue to operate its generation facility after the PPA has expired or terminated, perhaps with another off--taker. Any requirements and conditions for decommissioning of a generation facility owned by a third--party should be governed by the applicable permitting authorities.

### ~~16.2.1~~17 Energy Storage

-AB 2514, signed into law in September 2010, added Section 2837, which requires that the IOUs' RPS procurement plans incorporate any energy storage targets and policies that are adopted by the Commission as a result of its implementation of AB 2514. On October 17, 2013, the CPUC issued D.13-10-040 adopting an energy storage procurement framework and program design, requiring that PG&E execute 580 MW of storage capacity by 2020, with projects required to be installed and operational by no later than the end of 2024. In accordance with the guidelines in the decision, PG&E submitted an application to procure energy storage resources on February 28, 2014. In D.14-10-045, the CPUC approved PG&E's application with modifications. PG&E will file final storage RFO results for CPUC approval by December 1, 2015. In addition, PG&E is participating in a new proceeding, R.15-03-011, which the Commission opened in March 2015 to consider policy and implementation refinements to the energy storage procurement framework and program design.

PG&E considers eligible energy storage systems to help meet its Energy Storage Program targets through its RPS procurement process, Energy Storage RFO, as well as other CPUC programs and channels such as the Self Generation Incentive Program (SGIP). PG&E's LCBF methodology considers the additional value offered by RPS-eligible generation facilities that incorporate energy storage. Further detail on PG&E's energy storage procurement can be found in its biennial Energy Storage Plan.[103]

[103] *See* PG&E, *Application of Pacific Gas and Electric Company (U 39-E) for Authorization to Procure Energy Storage Resources (2014-2015 Biennial Cycle)*, (available at: http://www.cpuc.ca.gov/NR/rdonlyres/D9CACD21-AB1C-411A-8B79-84FB28E88C58/0/PGE_StorageApplication.pdf).

# APPENDIX D

## ~~2013 RPS~~ Procurement Information Related to Cost Quantification

~~December 23, 2014~~
August 4, 2015

# Appendix D~~: 2013 RPS~~ – Procurement Information Related to Cost Quantification

| Assumptions | |
|---|---|
| **Table 1 (Actual Costs, $) Items** | **Actual** |
| Rows 2 -- 8, 11 (2003-~~2013~~2014)[1, 2, 3, 4, 5, 6] | Settled contract costs with all RPS-eligible contracts in PG&E's portfolio for 2003-~~2013.~~2014 |
| Row 9 | For 2003-2011, capital costs are based on the net book value of PG&E's RPS-eligible units as of December 2011 multiplied by an assumed fixed charge rate equal to 14%. For 2012 ~~and 2013~~through 2014, capital costs are based on the net book value of PG&E's RPS-eligible units as of December of that respective year multiplied by a fixed charge rate of 14%. PG&E's actual operation and maintenance (O&M) costs for each year (2003-~~2013~~2014) were added to each year's capital costs to calculate total costs. |
| Row 10 | LCOE for each project multiplied by the project's historical generation |
| Row 13 | PG&E actual bundled retail sales |
| Row 14 | Total Cost / Bundled Retail Sales (Row 12 / Row 13) |
| **Table 2 (Forecast Costs, $) Items** | **Forecast** |
| Rows 2 -- 8, 11, 16 -- 22, 25 | PG&E's future expenditures on all RPS-eligible procurement and generation either (1) approved to date or (2) executed prior to April ~~2014~~2015 but pending ~~Commission~~CPUC approval~~ or (2) approved to date. The~~. 2015 data ~~further assumes no contract failure,~~represent a September 2014 vintage and ~~all contractual volumes are forecast at 100% of expected volumes.~~2016-2030 data represent a April 2015 vintage to be consistent with the 2015 Integrated Energy Policy Report (IEPR). |
| Rows 9 and 23 | For ~~2014~~2015-2030, annualized capital costs based on the net book value of PG&E's RPS-eligible units as of December ~~2013~~2014 were added to operation and maintenance (O&M) costs, which were calculated as ~~2013~~2014 O&M costs escalated at 5% annually for each year. |
| Row 10 and 24 | LCOE for each project multiplied by the project's forecasted generation |
| Rows 13 and 27 | PG&E bundled retail sales forecast |
| Rows 14 and 28 | Total Cost / Bundled Sales |
| Row 29 | Row 14 + Row 28 |
| **Table 3 (Actual Generation, MWh) Items** | **Actual** |
| Rows 2 -- 11[1, 3, 4, 5, 6] | Generation (MWh) associated with payments for RPS-eligible deliveries |
| **Table 4 (Forecast Generation, MWh) Items** | **Forecast** |
| Rows 2 -- 11 and 16-25 | Forecasted RPS-eligible generation (MWh) either (1) approved to date or (2) executed prior to April ~~2014~~2015 but pending Commission approval ~~or (2) approved to date. The data further~~-- assumes no contract failure, and all contractual volumes are forecast at 100% of expected volumes. 2015 data represent a September 2014 vintage and 2016-2030 data represent a April 2015 vintage to be consistent with the 2015 Integrated Energy Policy Report (IEPR). |

[1] 2014~~2012~~ Generation and Costs were updated to reflect best available data as of ~~January 2014~~March 2015.

[2] Row 5 includes the aggregate costs (specifically debt service and operation and maintenance) of PG&E's ~~contracts~~contract with Solano Irrigation ~~Districts and Water Agencies (Agency or Agencies) that supply~~District (SID) who supplies power from multiple ~~RPS- and non-~~hydro units, 100% of which are RPS-eligible~~ hydro units. Each Agency's~~. SID's costs include the costs to operate and maintain ~~multiple Agency~~the hydro units ~~(including RPS-eligible units and non-RPS-eligible units)~~ and project facilities (dams and waterways). ~~Since the~~ Yuba County Water Agency (YCWA) does not operate any RPS-eligible hydro units, therefore YCWA cost ~~assignments are made by Agency (not made by individual powerhouse), PG&E has approximated the costs associated with only RPS-eligible units through an allocation method. This method accounts for the fixed nature of the aggregate costs, and PG&E allocates the costs from each Agency using the RPS-eligible units' proportion of MW.~~data is not relevant and thereby not included.

[3] RPS-eligible generation ~~and costs~~ reported in ~~2013 are~~2014 is the best available settlements data as of ~~January 2014~~March 2015 and therefore ~~contain both~~contains actual ~~and estimated~~ data~~,~~ as settlements data for the prior year can continue to be adjusted after January of the current year. As UOG Hydro and UOG Solar estimates are calculated separately, 2013 data for these two technology types is the best available as of April 2014.

[4] Energy volumes reported in Rows 2-8 represent the generation (MWh) associated with payments for RPS-eligible deliveries, which can differ from the energy volumes PG&E claims for the purposes of complying with California's RPS Program. For example, some RPS contracts require PG&E to only pay for RPS-eligible deliveries based on scheduled energy, but entitle PG&E to all green attributes generated and metered by the facility. Since compliance with California's RPS Program is based on metered generation, scheduled/paid volumes may not always match the metered/compliance volumes.[4] ~~Costs for executed sales are a combination of geothermal and small hydro volumes. As the costs are a combined payment not divided by technology type, PG&E allocated technology-specific costs based on the technology-specific generation (MWh) of the sale contract.~~

[5] ~~PG&E has updated historical data for 2011 to correct its reported cost for a single wind contract. In the 2012 RPS Plan, a January 2012 payment for December 2011 deliveries was erroneously included for a single wind contract.~~[5] Cost for executed sales are a combination of geothermal and small hydro volumes. As the costs are a combined payment not divided by technology type, PG&E allocated technology specific costs based on the technology specific generation (MWh) of the sale contract.

# Appendix D~~: 2013 RPS~~ – Procurement Information Related to Cost Quantification

~~6~~6 Some immaterial changes have been made to cost and generation data from 2005, 2011, and 2013 as compared to the 2014 RPS Plan. 2005 changes are due to a 2006 RPS wind contract being accidently included in 2005. 2011 data changes are due to a mislabeling of a biogas contract as biomass. 2013 changes represent updated settlements data. ~~Energy volumes reported in Rows 2-8 represent the generation (MWh) associated with payments for RPS-eligible deliveries, which can differ from the energy volumes PG&E claims for the purposes of complying with California's RPS Program. For example, some RPS contracts require PG&E to only pay for RPS-eligible deliveries based on scheduled energy, but entitle PG&E to all green attributes generated and metered by the facility. Since compliance with California's RPS Program is based on metered generation, scheduled/paid volumes may not always match the metered/compliance volumes.~~

**Note** ~~1:~~: As with any forecasting exercise, projections are predicated on a number of necessarily speculative assumptions and will be impacted by future events, including regulatory decisions resulting in different costs or rate treatments. Thus, PG&E cannot guarantee that the information contained in this summary will reflect actual future rates, revenue requirements, or sales.

## Joint IOU Cost Quantification Table 1
## (Actual Costs, $ Thousands)

| | | Actual RPS-Eligible Procurement and Generation Costs | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Technology Type** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** |
| 2 | Biogas | $25,762 | $23,856 | $25,623 | $22,823 | $24,126 | $23,468 | $27,306 | $20,216 | $16,~~785~~776 | $5,333 | $5,~~236~~063 | $11,087 |
| 3 | Biomass | $215,078 | $217,923 | $217,279 | $222,125 | $238,524 | $259,957 | $262,086 | $263,994 | $~~246,225~~245,622 | $302,711 | $~~300,004~~299,205 | $317,301 |
| 4 | Geothermal | $110,572 | $111,778 | $108,720 | $118,523 | $199,143 | $282,227 | $200,357 | $260,053 | $~~240,533~~223,575 | $209,854 | $~~265,067~~284,334 | $324,050 |
| 5 | Small Hydro | $60,984 | $57,470 | $~~87,665~~80,340 | $97,340 | $63,161 | $72,488 | $52,053 | $63,296 | $~~89,421~~84,864 | $54,140 | $~~59,558~~57,213 | $45,522 |
| 6 | Solar PV | $0~~.358~~ | $0~~.270~~ | $0~~.310~~ | $0~~.205~~ | $0~~.051~~ | $0~~.051~~ | $2,554 | $10,180 | $33,~~365~~370 | $176,372 | $~~494,543~~504,860 | $803,806 |
| 7 | Solar Thermal | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $~~4,940~~1,698 | $173,856 |
| 8 | Wind | $65,244 | $74,912 | $~~66,061~~56,891 | $67,116 | $98,203 | $102,516 | $199,475 | $224,089 | $~~353,453~~340,517 | $379,416 | $~~431,729~~424,764 | $437,159 |
| 9 | UOG Small Hydro | $44,936 | $45,059 | $46,526 | $47,556 | $47,933 | $49,009 | $47,567 | $49,684 | $52,099 | $51,572 | $~~60,968~~64,691 | $66,066 |
| 10 | UOG Solar | $0 | $0 | $0 | $0 | $227 | $452 | $473 | $1,498 | $5,~~411~~620 | $27,~~687~~093 | $~~41,922~~43,882 | $52,426 |
| 11 | Unbundled RECs[1] | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | [redacted] | [redacted] | [redacted] | [redacted] |
| 12 | **Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 11] | **$522,576** | **$530,998** | **$~~551,874~~535,380** | **$575,483** | **$671,317** | **$790,116** | **$791,870** | **$893,010** | [redacted] | [redacted] | [redacted] | [redacted] |
| | ~~[Sum of Rows 2 through 11]~~ | | | | | | | | | [redacted] | [redacted] | [redacted] | [redacted] |
| 13 | Bundled Retail Sales [Thousands of kWh] | 71,099,363 | 72,113,608 | 72,371,532 | 76,356,279 | 79,078,319 | 81,523,859 | 79,624,479 | 77,485,129 | 74,863,941 | 76,205,120 | 75,705,039 | 74,546,865 |
| 14 | **Incremental Rate Impact**[2] | **0.73 ¢/kWh** | **0.74 ¢/kWh** | **0.~~76~~74 ¢/kWh** | **0.75 ¢/kWh** | **0.85 ¢/kWh** | **0.97 ¢/kWh** | **0.99 ¢/kWh** | **1.15 ¢/kWh** | [redacted] | [redacted] | [redacted] | [redacted] |

[1] The cost of Unbundled RECs are separated from their technology type and only reported in the Unbundled RECs row. For example, the cost of an Unbundled REC procured from a wind facility is only reported in the Unbundled RECs row.

[2] Incremental Rate Impact is equal to Row 12 divided by Row 13. While the item is labeled "Incremental Rate Impact~~"~~," the value should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable "premium~~"~~." In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

## Appendix D~~: 2013 RPS~~ – Procurement Information Related to Cost Quantification

### Joint IOU Cost Quantification Table 2
### (Forecast Costs, $ Thousands)

| # | | Forecasted Future Expenditures on RPS-Eligible Procurement and Generation Costs | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 1 | **Executed But Not CPUC-Approved RPS-Eligible Contracts** | **~~2014~~ 2015** | **2016** | **2017** | **2018** | **2019** | **2020** | |
| 2 | Biogas | $0 | $0 | $0 | $0 | $0 | $0 | ~~$0~~ |
| 3 | Biomass | $0 | $0 | $0 | $0 | $0 | $0 | ~~$0~~ |
| 4 | Geothermal | $0 | $0 | $0 | $0 | $0 | $0 | ~~$0~~ |
| 5 | Small Hydro | $0 | $0 | $0 | $0 | $0 | $0 | ~~$0~~ |
| 6 | Solar PV | $0 | $0 | $0 | $0 | $0 | $~~48,492~~0 | ~~$52,835~~ |
| 7 | Solar Thermal | $0 | $0 | $0 | $0 | $0 | $0 | ~~$0~~ |
| 8 | Wind | $0 | $0 | $0 | $0 | $0 | $0 | ~~$6,850~~ |
| 9 | UOG Small Hydro | $0 | $0 | $0 | $0 | $0 | $0 | ~~$0~~ |
| 10 | UOG Solar | $0 | $0 | $0 | $0 | $0 | $0 | ~~$0~~ |
| 11 | Unbundled RECs[1,~~2~~] | $0 | $0 | $0 | $0 | $0 | $0 | ~~$0~~ |
| 12 | **Total Executed But Not CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 11] | **$0** | **$0** | **$0** | **$0** | **$~~3,315~~0** | **$0** | **~~$59,685~~** |
| | ~~[Sum of Rows 2 through 11]~~ | | | | | | [redacted] | [redacted] |
| 13 | Bundled Retail Sales [Thousands of kWh] | ~~74,568,271~~71,182,544 | ~~75,102,903~~70,869,576 | [redacted] | 64,956,724 | ~~76,126,643~~62,381,387 | ~~76,350,858~~59,668,061 | ~~76,598,601~~ |
| 14 | **Incremental Rate ~~Impact~~[3]Impact[2]** | **0.000 ¢/kWh** | **0.000 ¢/kWh** | **0.000 ¢/kWh** | **0.000 ¢/kWh** | **0.~~004~~000 ¢/kWh** | [redacted] | **0.~~078~~000 ¢/kWh** |
| 15 | **CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)** | **~~2014~~ 2015** | **2016** | **2017** | **2018** | **2019** | **2020** | |
| 16 | Biogas | $~~16,036~~22,780 | $~~26,300~~23,189 | $~~31,108~~29,915 | $~~33,842~~29,994 | $~~33,884~~29,986 | $~~33,881~~30,143 | ~~$34,076~~ |
| 17 | Biomass | $~~323,752~~311,380 | $~~298,202~~270,577 | $~~285,794~~241,040 | $~~262,509~~219,990 | $~~237,966~~193,377 | $~~209,170~~136,275 | ~~$148,583~~ |
| 18 | Geothermal | $~~315,136~~329,015 | $~~336,425~~311,371 | $~~338,488~~314,874 | $~~344,103~~193,171 | $~~217,413~~194,611 | $~~220,887~~196,294 | ~~$225,667~~ |
| 19 | Small Hydro | $~~61,616~~76,539 | $~~73,867~~71,939 | $~~73,865~~62,257 | ~~$63,743~~ | $55,~~764~~181 | $52,~~642~~386 | $43,~~394~~648 |
| 20 | Solar PV | $~~747,496~~887,525 | $~~888,895~~914,533 | $~~912,579~~978,108 | $~~930,462~~983,227 | | ~~$931,909~~ | ~~$929,173~~ $~~9511~~1,008,9 $1,028,248 |

# Appendix D~~: 2013 RPS~~ – Procurement Information Related to Cost Quantification

| # | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | 77 |
| 21 | Solar Thermal | ~~$261,743~~ | $329,978 | $~~392,248~~329,961 | $~~557,811~~329,165 | $~~602,230~~328,838 | $~~602,141~~328,759 | $~~605,375~~330,446 | |
| 22 | Wind | $~~477,339~~449,274 | | $~~500,181~~432,664 | $~~488,153~~427,910 | $~~482,371~~425,276 | $~~481,188~~408,949 | $~~467,376~~409,845 | ~~$472,117~~ |
| 23 | UOG Small Hydro | $~~62,302~~67,407 | | ~~$63,703~~ | ~~$65,174~~ | ~~$66,718~~ $68,~~339~~815 | $70,~~042~~294 $71,~~829~~847 | $73,477 | $75,189 |
| 24 | UOG Solar | $~~53,689~~51,674 | | $~~53,411~~51,406 | $~~53,137~~51,139 | ~~$52,859~~ 50,874 | $~~52,584~~50,610 | $~~52,311~~50,347 | ~~$52,042~~ |
| 25 | Unbundled RECs[1] | | | $0 | $0 | $0 | $0 | $0 | ~~$0~~ |
| 26 | **Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 16 through 25] | | | | **$2,~~640,546~~474,455** | **$2,~~794,417~~504,704** | **$2,~~681,277~~358,397** | **$2,~~637,623~~341,133** | **$2,~~605,059~~300,435** |
| | ~~[Sum of Rows 16 through 25]~~ | | | | | | | | |
| 27 | Bundled Retail Sales [Thousands of kWh] | ~~74,568,271~~71,182,544 | | ~~75,102,903~~70,869,576 | | 64,956,724 | ~~76,126,643~~62,381,387 | ~~76,350,858~~59,668,061 | ~~76,598,601~~ |
| 28 | **Incremental Rate ~~Impact~~[3]Impact[2]** | | | **3.49 ¢/kWh** | | | **3.~~52~~63 ¢/kWh** | **3.~~45~~75 ¢/kWh** | **3.~~40~~86 ¢/kWh** |
| 29 | **Total Incremental Rate Impact** [Row 14 + 28; Rounding can cause Row 29 to differ from Row 14 + 28] | | | | **3.~~50~~49 ¢/kWh** | **3.~~69~~63 ¢/kWh** | **3.~~53~~75 ¢/kWh** | | **3.~~48~~86 ¢/kWh** |
| | ~~[Row 14 + 28; Rounding can cause Row 29 to differ from Row 14 + 28]~~ | | | | | | | | |

[1] See footnote 1 from Table 1.

~~[2] The volumes for three contracts per Res E-4649 have been removed from this table as a result of the CPUC denying PG&E's request for the approval of the associated PSAs.~~

~~[3]~~[2] Incremental Rate Impact is equal to a Total Cost (either Row 12 or 26) divided by Bundled Retail Sales (either Row 13 or 27). While the item is labeled "Incremental Rate Impact~~",~~," the value should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable "premium~~".~~." In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

## Appendix D~~: 2013 RPS~~ – Procurement Information Related to Cost Quantification

### Joint IOU Cost Quantification Table 2 (continued)
### (Forecast Costs, $ Thousands)

| | | Forecasted Future Expenditures on RPS-Eligible Procurement and Generation Costs | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Executed But Not CPUC-Approved RPS-Eligible Contracts** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| 2 | Biogas | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 3 | Biomass | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4 | Geothermal | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 5 | Small Hydro | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 6 | Solar PV | $~~55,244~~0 | $~~55,053~~0 | $~~54,807~~0 | $~~54,631~~0 | $~~54,455~~0 | $~~54,488~~0 | $~~54,232~~0 | $~~54,073~~0 | $~~53,760~~0 | $~~53,587~~0 |
| 7 | Solar Thermal | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 8 | Wind | $~~7,262~~0 | $~~7,262~~0 | $~~7,257~~0 | $~~7,258~~0 | $~~7,253~~0 | $~~7,273~~0 | $~~7,262~~0 | $~~7,266~~0 | $~~7,253~~0 | $~~7,249~~0 |
| 9 | UOG Small Hydro | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 10 | UOG Solar | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 11 | Unbundled RECs[1]~~,2~~ | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12 | **Total Executed But Not CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 11] | **$~~62,506~~0** | **$~~62,314~~0** | **$~~62,063~~0** | **$~~61,889~~0** | **$~~61,708~~0** | **$~~61,761~~0** | **$~~61,494~~0** | **$~~61,339~~0** | **$~~61,013~~0** | **$~~60,836~~0** |
| 13 | Bundled Retail Sales [Thousands of kWh] | ~~76,866,066~~ 59,779,916 | ~~77,148,308~~ 59,888,425 | ~~77,447,971~~ 59,987,654 | ~~77,755,293~~ 60,077,196 | ~~78,071,098~~ 60,188,640 | ~~78,406,194~~ 60,407,333 | ~~78,746,853~~ 60,765,057 | ~~79,099,588~~ 61,330,567 | ~~79,449,111~~62,066,738 | ~~79,806,984~~ 62,947,785 |
| 14 | **Incremental Rate ~~Impact[3]~~Impact[2]** | **0.~~08~~00 ¢/kWh** | **0.~~08~~00 ¢/kWh** | **0.~~08~~00 ¢/kWh** | **0.~~08~~00 ¢/kWh** | **0.~~08~~00 ¢/kWh** | **0.~~08~~00 ¢/kWh** | **0.~~08~~00 ¢/kWh** | **0.~~08~~00 ¢/kWh** | **0.~~08~~00 ¢/kWh** | **0.~~08~~00 ¢/kWh** |
| 15 | **CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| 16 | Biogas | $~~34,014~~30,098 | $~~34,095~~30,190 | $~~34,071~~30,175 | $~~34,008~~29,839 | $~~33,833~~29,408 | $~~33,543~~29,107 | $~~33,620~~29,167 | $~~33,749~~29,288 | $~~31,640~~27,193 | $~~31,342~~26,884 |
| 17 | Biomass | $~~139,503~~127,551 | $~~140,497~~128,345 | $~~141,413~~129,109 | $~~142,734~~130,224 | $~~143,509~~130,865 | $~~144,398~~131,575 | $~~112,710~~99,946 | $~~102,679~~95,123 | $~~102,692~~95,038 | $~~103,018~~95,228 |
| 18 | Geothermal | $~~229,890~~196,819 | $~~27,762~~13,563 | $~~27,653~~13,470 | $~~27,629~~13,423 | $~~27,496~~13,314 | $~~27,469~~13,256 | $~~27,375~~13,174 | $~~27,339~~13,121 | $~~27,167~~12,997 | $~~27,092~~12,921 |
| 19 | Small Hydro | $35,~~157~~937 | $29,~~018~~846 | $~~28,146~~29,039 | $~~28,393~~29,202 | $~~27,982~~28,968 | $~~28,341~~29,258 | $~~28,758~~29,666 | $~~28,814~~29,695 | $~~23,515~~24,716 | $~~23,600~~24,619 |
| 20 | Solar PV | $~~945,932~~1,024,724 | $~~943,239~~1,021,926 | $~~939,429~~1,017,959 | $~~937,714~~1,016,112 | $~~934,778~~1,013,141 | $~~935,519~~1,014,002 | $~~931,923~~1,010,252 | $~~930,179~~1,008,497 | $~~922,437~~1,000,500 | $~~918,992~~996,987 |
| 21 | Solar Thermal | $~~603,635~~329,547 | $~~603,554~~329,514 | $~~602,849~~329,165 | $~~603,100~~329,232 | $~~602,729~~329,063 | $~~604,417~~329,978 | $~~603,635~~329,547 | $~~603,808~~329,639 | $~~602,230~~328,838 | $~~602,141~~328,759 |
| 22 | Wind | $~~469,407~~403,463 | $~~466,309~~397,706 | $~~447,038~~378,153 | $~~424,284~~353,862 | $~~423,335~~351,789 | $~~360,109~~287,146 | $~~361,769~~287,350 | $~~364,175~~288,065 | $~~329,053~~251,628 | $~~329,937~~250,960 |
| 23 | UOG Small Hydro | $~~73,706~~76,987 | $~~75,677~~78,874 | $~~77,746~~80,856 | $~~79,919~~82,937 | $~~82,200~~85,122 | $~~84,596~~87,416 | $~~87,111~~89,825 | $~~89,752~~92,354 | $~~92,525~~95,010 | $~~95,437~~97,798 |
| 24 | UOG Solar | $~~51,735~~50,086 | $~~51,455~~49,826 | $~~51,176~~49,568 | $~~50,898~~49,311 | $~~50,621~~49,055 | $~~50,346~~48,801 | $~~50,073~~48,548 | $~~49,800~~48,296 | $~~49,529~~48,045 | $~~49,260~~47,796 |
| 25 | Unbundled RECs[1] | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 26 | **Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 16 through 25] | **$2,~~582,979~~275,213** | **$2,~~371,605~~079,790** | **$2,~~349,521~~057,495** | **$2,~~328,678~~034,141** | **$2,~~326,485~~030,724** | **$~~2,268,739~~1,970,537** | **$~~2,236,974~~1,937,475** | **$~~2,230,296~~1,934,078** | **$~~2,180,790~~1,883,965** | **$~~2,180,818~~1,881,953** |
| 27 | Bundled Retail Sales [Thousands of kWh] | ~~76,866,066~~ 59,779,916 | ~~77,148,308~~ 59,888,425 | ~~77,447,971~~ 59,987,654 | ~~77,755,293~~ 60,077,196 | ~~78,071,098~~ 60,188,640 | ~~78,406,194~~ 60,407,333 | ~~78,746,853~~ 60,765,057 | ~~79,099,588~~ 61,330,567 | ~~79,449,111~~62,066,738 | ~~79,806,984~~ 62,947,785 |
| 28 | **Incremental Rate ~~Impact[3]~~Impact[2]** | **3.~~36~~81** | **3.~~07~~47** | **3.~~03~~43** | **~~2.99~~3.39** | **~~2.98~~3.37** | **~~2.89~~3.26** | **~~2.84~~3.19** | **~~2.82~~3.15** | **~~2.74~~3.04** | **2.~~73~~99** |

## Appendix D~~: 2013 RPS~~ – Procurement Information Related to Cost Quantification

| | | ¢/kWh | ¢/kWh | ¢/kWh | ¢/kWh | ¢/kWh | ¢/kWh | ¢/kWh | ¢/kWh | ¢/kWh | ¢/kWh |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 29 | **Total Incremental Rate Impact** [Row 14 + 28; Rounding can cause Row 29 to differ from Row 14 + 28] | **3.~~44~~81 ¢/kWh** | **3.~~15~~47 ¢/kWh** | **3.~~11~~43 ¢/kWh** | **3.~~07~~39 ¢/kWh** | **3.~~06~~37 ¢/kWh** | **~~2.97~~3.26 ¢/kWh** | **~~2.92~~3.19 ¢/kWh** | **~~2.90~~3.15 ¢/kWh** | **~~2.82~~3.04 ¢/kWh** | **2.~~81~~99 ¢/kWh** |

[1] See footnote 1 from Table 1.

~~[2] The volumes for three contracts per Res E-4649 have been removed from this table as a result of the CPUC denying PG&E's request for the approval of the associated PSAs.~~

[~~3~~2] Incremental Rate Impact is equal to a Total Cost (either Row 12 or 26) divided by Bundled Retail Sales (either Row 13 or 27). While the item is labeled "Incremental Rate Impact~~"~~," the value should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable "premium~~"~~." In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

# Appendix D~~: 2013 RPS~~ – Procurement Information Related to Cost Quantification

## Joint IOU Cost Quantification Table 3
## (Actual Generation, MWh)

| | | Actual RPS-Eligible Procurement and Generation (MWh) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Technology Type** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012~~2012[1]~~** | **2013** | **2014** |
| 2 | Biogas | 364,745 | 333,897 | 366,514 | 300,943 | 293,147 | 280,795 | 342,362 | 306,909 | 284,~~227~~129 | 112,153 | ~~88,204~~85,706 | 112,161 |
| 3 | Biomass | 2,839,795 | 2,961,633 | 2,858,643 | 2,770,398 | 2,751,813 | 2,813,819 | 3,122,048 | 2,990,615 | 3,~~044,943~~043,656 | 3,158,131 | 3,~~098,003~~055,370 | 3,226,904 |
| 4 | Geothermal | 1,674,702 | 1,753,043 | 1,687,360 | 1,790,870 | 2,701,970 | 3,350,232 | 3,411,798 | 3,766,700 | 3,~~781,028~~780,954 | 3,807,728 | 3,~~698,268~~687,236 | 3,870,952 |
| 5 | Small Hydro | 1,269,233 | 1,096,183 | 1,~~531,501~~457,339 | 1,760,707 | 927,879 | 945,921 | 937,626 | 1,092,707 | 1,~~473,652~~457,714 | 863,606 | ~~701,433~~652,953 | 400,300 |
| 6 | Solar PV | 6 | 4 | 4 | 3 | 1 | 1 | 21,706 | 58,593 | ~~178,808~~179,171 | 1,006,145 | 3,~~257,628~~358,366 | 5,266,030 |
| 7 | Solar Thermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | ~~34,718~~20,581 | 878,905 |
| 8 | Wind | 940,239 | 1,078,579 | ~~1,060,926~~874,204 | 1,019,451 | 1,374,337 | 1,439,796 | 2,557,988 | 2,981,660 | 4,~~506,867~~395,377 | 4,515,452 | 4,~~979,493~~924,052 | 5,358,546 |
| 9 | UOG Small Hydro | 1,382,934 | 1,267,084 | 1,403,130 | 1,437,196 | 984,607 | 993,266 | 1,103,017 | 1,157,077 | 1,254,638 | 948,734 | ~~929,045~~1,394,189 | 1,292,552 |
| 10 | UOG Solar | 0 | 0 | 0 | 0 | 225 | 445 | 504 | 4,642 | ~~28,140~~26,790 | 165,~~319~~656 | ~~272,718~~279,500 | 336,905 |
| 11 | Unbundled RECs[2] | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 102,888 | 108,874 | 101,256 | 100,581 |
| 12 | **Total CPUC-Approved RPS-Eligible Procurement and Generation** [Sum of Rows 2 through 11] | 8,471,654 | 8,490,423 | 8,~~908,078~~647,195 | 9,079,568 | 9,033,979 | 9,824,276 | 11,497,048 | 12,358,903 | 14,~~655,191~~525,317 | 14,686,~~142~~479 | 17,~~160,766~~559,209 | 20,843,836 |
| | ~~[Sum of Rows 2 through 11]~~ | | | | | | | | | | | | |

[1] Energy Volumes reported for ~~2012~~2014 in Rows 2 – 11 are the best available settlements data as of ~~January 2014~~March 2015.

[2] Row 11 only includes Unbundled RECs with CPUC approval.

~~**Note**: Energy Volumes reported in Rows 2 – 8 represent the MWh associated with payments for RPS-eligible deliveries, which can differ from the energy volumes PG&E claims for the purposes of complying with California's RPS program. For example, some RPS contracts require PG&E to only pay for RPS-eligible deliveries based on scheduled energy, but entitle PG&E to all green attributes generated and metered by the facility. Since compliance with California's RPS program is based on metered generation, scheduled/paid volumes may not always match the metered/compliance volumes.~~

# Appendix D~~: 2013 RPS~~ – Procurement Information Related to Cost Quantification

## Joint IOU Cost Quantification Table 4
## (Forecast Generation, MWh)

| | Forecasted Future RPS-Deliveries ~~2014~~2015-2020 (MWh) | | | | |
|---|---|---|---|---|---|
| 4 | 2015 | 2016 | 2017 | 2018 | 2019 |
| | | | | | |
| iogas | 0 | 0 | 0 | 0 | 0 |
| mass | 0 | 0 | 0 | 0 | 0 |
| ermal | 0 | 0 | 0 | 0 | 0 |
| Hydro | 0 | 0 | 0 | 0 | 0 |
| ar PV | 0 | 0 | 0 | 0 | ~~532~~0 |
| ermal | 0 | 0 | 0 | 0 | 0 |
| Wind | 0 | 0 | ~~31,482~~0 | ~~62,000~~0 | ~~62,000~~0 |
| Hydro | 0 | 0 | 0 | 0 | 0 |
| Solar | 0 | 0 | 0 | 0 | 0 |
| RECs | 0 | 0 | 0 | 0 | 0 |
| **eries** gh 11] | 0 | 0 | ~~31,482~~0 | ~~62,000~~0 | ~~62,532~~0 |
| ~~ugh 11]~~ | | | | | |
| 4 | 2015 | 2016 | 2017 | 2018 | 2019 |
| | | | | | |
| iogas | ~~162,266~~213,398 | ~~244,141~~215,310 | ~~277,783~~267,185 | ~~301,244~~267,182 | ~~301,219~~2665 |
| mass | 3,~~208,519~~040,682 ~~3,043,414~~ ~~3,014,209~~ | 2,~~810,462~~872,745 | 2,~~504,610~~656,538 | 2,~~109,311~~351,353 | 1,~~366,480~~9668 |
| ~~086~~ | 3,940,027 | 3,~~955,554~~846,522 | 3,~~952,295~~835,023 | 2,~~445,315~~319,523 | 2,~~446,415~~3615 |
| Hydro | ~~738,369~~1,055,888 | ~~939,256~~919,433 | ~~980,832~~830,771 | ~~840,931~~756,106 | ~~750,576~~7097 |
| ~~997~~ | 6,~~041,304~~034,952 | 6,~~325,016~~312,897 | ~~6,490,256~~7,174,123 | ~~6,495,468~~7,238,882 | ~~6,453,211~~71,317 |
| ermal | 1,~~403,491~~780,838 | 1,783,858 | 1,780,838 | ~~2,083,751~~1,780,838 | ~~3,083,380~~10,838 |
| Wind | ~~5,360,549~~4,355,465 | ~~5,690,296~~4,118,960 | ~~5,491,418~~4,026,183 | ~~5,338,258~~3,970,422 | ~~5,270,713~~35,438 |
| ~~65~~ | 1,~~255,154~~251,112 | 1,~~385,928~~151,280 | 1,~~420,299~~361,309 | 1,~~441,474~~433,494 | 1,~~447,976~~4994 |
| ~~15~~ | 343,~~413~~053 | ~~342,386~~329,694 | ~~339,853~~327,253 ~~338,087~~ ~~336,331~~ | ~~335,~~325,551 | 323,857 |
| RECs | 100,000 | ~~100,000~~0 | 0 | 0 | 0 |

# Appendix D~~: 2013 RPS~~ – Procurement Information Related to Cost Quantification

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| eries gh 25] | 22,115,415 | 21,~~191,257~~550,699 | ~~23,377,842~~ | ~~23,856,876~~ | ~~24,576,979~~ | 22,~~922,627~~259,225 | ~~22,219,891~~20,443,351 | ~~21,560,841~~159,379 |
| ~~ugh 25]~~ | | | | | | | | |

~~[1] The volumes for three contracts per Res E-4649 have been removed from this table as a result of the CPUC denying PG&E's request for the approval of the associated PSAs.~~

# Appendix D~~: 2013 RPS~~ – Procurement Information Related to Cost Quantification

## Joint IOU Cost Quantification Table 4 (continued)
## (Forecast Generation, MWh)

| | | Forecasted Future RPS-Deliveries 2021-2030 (MWh) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Executed But Not CPUC-Approved** **RPS-Eligible Contracts** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| | ~~**RPS-Eligible Contracts**~~ | | | | | | | | | | |
| 2 | Biogas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | Biomass | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4 | Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5 | Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 6 | Solar PV | ~~819,464~~0 | ~~815,104~~0 | ~~811,028~~0 | ~~808,506~~0 | ~~802,938~~0 | ~~798,924~~0 | ~~794,929~~0 | ~~792,456~~0 | ~~787,000~~0 | ~~783,065~~0 |
| 7 | Solar Thermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Wind | ~~114,923~~0 | ~~114,923~~0 | ~~114,923~~0 | ~~115,092~~0 | ~~114,923~~0 | ~~114,923~~0 | ~~114,923~~0 | ~~115,092~~0 | ~~114,923~~0 | ~~114,923~~0 |
| 9 | UOG Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | UOG Solar | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 11 | Unbundled ~~RECs[1]~~RECs | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 12 | **Total Executed But Not CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 2 through 11] | ~~934,387~~0 | ~~930,027~~0 | ~~925,951~~0 | ~~923,597~~0 | ~~917,861~~0 | ~~913,847~~0 | ~~909,852~~0 | ~~907,548~~0 | ~~901,923~~0 | ~~897,988~~0 |
| | ~~[Sum of Rows 2 through 11]~~ | | | | | | | | | | |
| 15 | **CPUC-Approved RPS-Eligible Contracts** **(Incl. RAM/FIT/PV Contracts)** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| | ~~**(Incl. RAM/FIT/PV Contracts)**~~ | | | | | | | | | | |
| 16 | Biogas | ~~299,407~~265,270 | ~~299,383~~265,284 | ~~298,850~~264,803 | ~~298,653~~261,746 | ~~296,001~~256,235 | ~~291,722~~251,874 | ~~291,701~~251,827 | ~~292,421~~252,519 | ~~280,569~~240,795 | ~~278,373~~238,613 |
| 17 | Biomass | 1,~~238,586~~090,072 | 1,~~238,468~~090,072 | 1,~~238,409~~090,072 | 1,~~241,577~~092,821 | 1,~~238,538~~090,072 | 1,~~235,761~~087,042 | ~~1,028,487~~882,505 | ~~954,998~~851,855 | ~~952,625~~849,722 | ~~952,618~~849,722 |
| 18 | Geothermal | 2,~~444,615~~316,815 | ~~280,029~~152,229 | ~~279,142~~151,342 | ~~279,091~~150,941 | ~~277,384~~149,584 | ~~276,513~~148,713 | ~~275,646~~147,846 | ~~275,604~~147,454 | ~~273,929~~146,129 | ~~273,078~~145,278 |
| 19 | Small Hydro | ~~485,354~~498,763 | ~~400,504~~413,322 | ~~379,407~~392,430 | ~~379,708~~391,039 | ~~370,708~~384,319 | ~~370,585~~383,913 | ~~371,163~~383,483 | ~~365,906~~378,818 | ~~319,829~~333,264 | ~~316,388~~328,828 |
| 20 | Solar PV | ~~6,560,688~~7,724,673 | ~~6,517,277~~7,675,085 | ~~6,474,172~~7,626,096 | ~~6,445,001~~7,593,239 | ~~6,388,869~~7,529,116 | ~~6,346,667~~7,481,119 | ~~6,304,761~~7,433,449 | ~~6,276,420~~7,401,497 | ~~6,203,466~~7,320,714 | ~~6,155,938~~7,267,509 |
| ~~21~~ | ~~Solar Thermal~~ | ~~3,375,165~~ | ~~3,375,165~~ | ~~3,375,165~~ | ~~3,381,463~~ | ~~3,375,165~~ | ~~3,375,165~~ | ~~3,375,165~~ | ~~3,381,463~~ | ~~3,375,165~~ | ~~3,375,165~~ |
| ~~22~~ | ~~Wind~~ | ~~4,928,085~~ | ~~4,813,679~~ | ~~4,540,206~~ | ~~4,288,468~~ | ~~4,256,501~~ | ~~3,739,047~~ | ~~3,739,047~~ | ~~3,746,449~~ | ~~3,323,122~~ | ~~3,312,679~~ |
| ~~23~~21 | Solar Thermal~~UOG Small Hydro~~ | 1,~~447,228~~780,838 | 1,~~448,126~~780,838 | 1,~~449,007~~780,838 | 1,~~453,999~~783,858 | 1,~~449,234~~780,838 | 1,~~449,018~~780,838 | 1,~~452,677~~780,838 | 1,~~447,908~~783,858 | 1,~~443,436~~780,838 | 1,~~440,656~~780,838 |
| 22 | Wind | 3,640,391 | 3,525,985 | 3,252,513 | 2,997,365 | 2,968,807 | 2,451,353 | 2,451,353 | 2,455,346 | 2,035,428 | 2,024,985 |
| 23 | UOG Small Hydro | 1,467,619 | 1,467,824 | 1,467,546 | 1,470,461 | 1,466,095 | 1,468,461 | 1,466,608 | 1,471,677 | 1,463,931 | 1,468,041 |
| 24 | UOG Solar | ~~332,845~~320 | ~~331,116~~318 | ~~329,396~~317 | ~~328,411~~316 | ~~325,982~~31 | ~~324,289~~31 | ~~322,604~~310 | ~~321,640~~309 | ~~319,261~~307 | ~~317,603~~305 |

# Appendix D~~: 2013 RPS~~ – Procurement Information Related to Cost Quantification

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | ,496 | ,829 | ,170 | ,219 | 3,879 | 2,246 | ,622 | ,691 | ,399 | ,800 |
| 25 | Unbundled RECs | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 26 | **Total CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 16 through 25] | ~~21,111,973~~ 19,104,938 | ~~18,703,748~~ 16,689,467 | ~~18,363,753~~ 16,342,810 | ~~18,096,369~~ 16,057,689 | ~~17,978,382~~ 15,938,944 | ~~17,408,766~~ 15,365,560 | ~~17,161,251~~ 15,108,532 | ~~17,062,809~~ 15,052,716 | ~~16,491,401~~ 14,478,219 | ~~16,422,499~~ 14,409,613 |
| | ~~[Sum of Rows 16 through 25]~~ | | | | | | | | | | |

~~[1] The volumes for three contracts per Res E-4649 have been removed from this table as a result of the CPUC denying PG&E's request for the approval of the associated PSAs.~~

# APPENDIX G

## Other Modeling Assumptions Informing Quantitative Calculation

~~December 23, 2014~~
August 4, 2015

# Appendix G~~:~~ – Other Modeling Assumptions Informing Quantitative Calculation

| - | ~~**Assumptions**~~ |
|---|---|
| **Compliance Periods** ~~**Re-contracting**~~ | ~~**Delivery**~~ **Assumptions** ~~**(Signed Contracts)**~~ • ~~For~~As implemented by D.11-12-020, SB 2 1X requires retail sellers of electricity to meet the following ~~this risk-adjusted forecast does not assume that expiring (non-signed) contracts are re-signed~~ • ~~Except for those "Closely Watched" contracts (see Section 6), all signed contracts are assumed to deliver at 100% of contract volumes, and deliveries commence within the allowed delay provisions in the contract.~~ |
| **Related to Procurement Quantity Requirement** | |
| ~~**Operational Projects**~~<br><br>~~*Contracts Executed Post-2002*~~ | • ~~Forecast is based on contract volumes or a blended three year average output (for projects with at least a full calendar year of deliveries PG&E averages annual contract quantities with available actuals).~~<br>• ~~Year 2014 deliveries: Recorded meter data replaces forecasted deliveries for all projects as it becomes available.~~ |
| ~~**Baseline Non-Hydro**~~<br><br>~~*Pre-2002, QF Contracts*~~ | • ~~PG&E forecasts non-hydro QF projects at 95% of their 3-year average output, with the slight reduction based on the observation that, for a variety of reasons, these older resources (as a portfolio) have tended to under-deliver when compared to their average historical performance.~~<br>• ~~Year 2014 deliveries: Recorded meter data (as available) replaces forecasted deliveries for all projects.~~ |
| ~~**Baseline Small Hydro**~~<br><br>~~*Pre-2002 QF, Irrigation District, and legacy utility-owned assets*~~ | • ~~Projects are forecast at 57% of normal for 2014 (based on PG&E's latest internal hydro delivery forecast), 85% of normal for 2015, and 100% of normal for future years.~~<br>• ~~Year 2014 deliveries: Recorded deliveries are used in place of forecasts as they become available.~~ |

| | |
|---|---|
| | ~~1.~~ RPS ~~PG&E does not yet have contractual commitments for these expiring volumes;~~<br>~~2. A number of the expiring contracts are with aging generating facilities with limited remaining useful life;~~<br>~~3. Contract-renewal bids may not be competitive with offers for new projects received in the current or future solicitations; and~~<br>~~4. Assuming re-contracted volumes obscures PG&E's current real need for additional energy in later years.~~<br><br>• ~~Re-contracting is not precluded by this assumption, but rather it reflects that re-contracting will be considered in the future side-by-side with~~ procurement ~~of other new resources.~~quantity requirements beginning on January 1, 2011:<br>o An average of twenty percent of the combined bundled retail sales during the first compliance period (2011-2013).<br>o Sufficient procurement during the second compliance period (2014-2016) that is consistent with the following formula: (.217 * 2014 retail sales) + (.233 * 2015 retail sales) + (.25 * 2016 retail sales).<br>o Sufficient procurement during the third compliance period (2017-2020) that is consistent with the following formula: (.27 * 2017 retail sales) + (.29 * 2018 retail sales) + (.31 * 2019 retail sales) + (.33 * 2020 retail sales).<br>o 33 percent of bundled retail sales in 2021 and all years thereafter.~~This forecasting methodology (i.e. not assuming any re-contracting) is consistent with PG&E's Annual RPS compliance filing that only shows PG&E's current contractual commitments.~~<br>• Under the 40 percent scenario, requirements that are consistent with the following formula: (.33 * 2021 retail sales) + (.37 * 2022 retail sales) + (.37 * 2023 retail sales) + (.40 * 2024 retail sales) and beyond. |
| ~~**Shortlisted Projects**~~<br><br>~~*From 2013 Solicitation or Bilateral Offer*~~ | ~~• No shortlisted projects are included in PG&E's forecast.~~<br>~~• Only executed contracts, or generic deliveries from pre-approved procurement programs (i.e., PV Program, RAM, and Feed-in Tariffs) are included in PG&E's forecast.~~ |

# Appendix G~~:~~ – Other Modeling Assumptions Informing Quantitative Calculation

## Other Modeling Assumptions Informing Quantitative Calculation[1]

| Assumptions Related to Forecasted Generation | |
|---|---|
| ~~**Future Volumes from Pre-Approved Programs**~~**Non-QF Projects**<br><br>*Contracts Executed Post-2002* | ~~**Feed-in Tariffs**~~<br>Except for the "OFF/Closely Watched" contract category (see Section 4), all non-QF signed<br>~~**E-SRG, E-PWF (AB 1969 FIT)**~~<br>• ~~All deliveries from executed~~ contracts are assumed ~~at 100% of contract volumes.~~<br>• to deliver~~Annual energy volumes (for non-operating projects) are modeled based on PG&E's best estimate for project start dates/initial energy delivery date.~~<br><br>~~**ReMAT**~~<br>• ~~All deliveries from executed contracts are assumed~~ at 100% of contract volumes~~.~~<br>• ~~Modeled start date for generic volumes assumed to begin 7/1/2016~~, and ~~ramp up linearly until 5/1/2018, reaching a total of ~120 MW.~~<br>deliveries commence within the allowed delay provisions in the contract<br>~~**SB1122 (Bioenergy Feed-in Tariff Program)**~~<br>• ~~Modeled start date for generic volumes assumed to begin 7/1/2017 and ramp up linearly until 5/1/2019, reaching a total of ~111 MW~~. |
| **QF Non-Hydro Projects**<br><br>*Contracts Executed Pre-2002* | • Forecast is typically based on an average of the three most recent calendar year deliveries.<br>• Year 2015 deliveries: Recorded meter data replaces forecasted deliveries for all projects as it becomes available. |

1 All assumptions in this table reflect an April 30, 2015 data vintage which is consistent with the data vintage of Appendices C1 – C4.

# Appendix G: – Other Modeling Assumptions Informing Quantitative Calculation

| | |
|---|---|
| **QF Hydro**<br><br>*Pre-2002 QF, Irrigation District, and Legacy Utility-Owned Assets* | • Forecast is typically based on historical production, calendar year deliveries, and regularly updated with PG&E's latest internal hydro updates.<br>• Projects are forecasted at 48% of average water year generation for 2015 (based on PG&E's April 30, 2015 vintage internal hydro delivery forecast) and reverting to average water years in later years.<br>• Year 2015 deliveries: Recorded meter data replaces forecasted deliveries for all projects as it becomes available. |
| **Non-QF Hydro**<br><br>*Utility Owned Generation (UOG) and Irrigation District Water Authority (IDWA)* | Forecasts reflect<br>~~**Renewable Auction Mechanism (Remaining Capacity)**~~<br><br>• ~~For planning purposes~~ PG&~~E assumed a project start date equal to 5/1/2017.~~<br>• ~~Technology mix assumed to be 10 MW of baseload, 20 MW of as-~~E's best available ~~non-peaking, and ~60 MW of as-available peaking~~projections for hydro conditions.<br>• ~~All deliveries from executed contracts are assumed at 100% of contract volumes.~~<br>• Projects are forecasted at 48% of average water year generation for 2015 (based on PG&E's April 30, 2015 vintage internal hydro delivery forecast) and reverting to average water years in later years.<br>• Year 2015 deliveries: Recorded meter data replaces forecasted deliveries for all projects as it becomes available. |
| **Future Volumes from Pre-Approved Programs** | **Feed-in Tariffs**<br><br>**E-SRG, E-PWF (AB 1969 FIT)**<br>• All deliveries from executed contracts are assumed at 100% of contract volumes.<br>• Annual energy volumes (for non-operating projects) are modeled based on PG&E's best estimate for project start dates/initial energy delivery date.<br><br>**ReMAT**<br>• All deliveries from executed contracts are assumed at 100% of contract volumes.<br>• Modeled start date for generic volumes assumed to begin 7/1/2016 and ramp up linearly until 1/1/2019, reaching a total of ~114 MW. |

# Appendix G~~:~~ – Other Modeling Assumptions Informing Quantitative Calculation

**SB1122 (Bioenergy Feed-in Tariff Program)**

- Modeled start date for generic volumes assumed to begin 7/1/2017 and ramp up linearly until 7/1/2021, reaching a total of ~111 MW.

**Renewable Auction Mechanism (Remaining Capacity)**

- For planning purposes PG&E assumed a project start date equal to 12/1/2017.
- Technology mix assumed to be 32 MW of as-available peaking.
- All deliveries from executed contracts are assumed at 100% of contract volumes.

**PV Originally Authorized for PG&E Photovoltaic Program**

- ~~PG&E filed an updated PV PPA Program protocol and PPA via a Tier 3 Advice Letter on February 28, 2014 for its Year 3 PV PPA RFO for 58 MW.~~
- Consistent with PG&E's February 26, 2014 Petition for Modification (PFM)[2] requesting to terminate the PV~~-~~ Program and modify the RAM Decision process to procure the remaining PV Program volumes using RAM solicitation processes PG&E assumed that the Renewable Auction Mechanism accommodates the remaining 200~~-~~ MW of PG&E's PV Program volumes.
- For planning purposes, PG&E has assumed that ~~58~~ a total of 209 MW ~~starts on 1/1/~~will be coming online between 2017~~, 100 MW on 1/1/~~ and 2018~~, and 100 MW on 1/1/2019 (30 months~~.[3]
- All deliveries from executed contracts are assumed at 100% of contract ~~approvals in 7/1/2014 through 7/1/2016, respectively).~~
- ~~All deliveries from executed contracts are assumed at 100% of contract volumes.~~volumes.

2 Advice Letter 3809-E. http://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/RAM/ELEC_3809-E.pdf.

3 This assumption is based on a modeling vintage of April 2015.

## Appendix G~~:~~ – Other Modeling Assumptions Informing Quantitative Calculation

| | |
|---|---|
| Re-contracting~~Compliance Period Procurement Quantity Requirements~~ | • ~~As implemented by D.11-12-020, SB 2 1X requires retail sellers of electricity to meet~~For the following reasons this risk-adjusted forecast does not assume that expiring volumes are retained:<br>1. PG&E does not yet have contractual commitments for these expiring volumes;<br>2. A number of the expiring contracts are with aging generating facilities with limited remaining useful life;<br>3. Contract-renewal bids may not be competitive with offers for new projects received in future solicitations; and<br>4. Assuming re-contracted volumes obscures PG&E's current real need for additional energy in later years.<br>• ~~RPS~~ Re-contracting is not precluded by this assumption, but rather it reflects that re-contracting will be considered in the future side-by-side with procurement ~~quantity requirements beginning on January 1, 2011:~~of other new resources.<br>• ~~An average of twenty percent of the combined bundled retail sales during the first compliance period (2011-2013).~~<br>This forecasting methodology (i.e. not assuming any re-contracting) is consistent with PG&E's Annual RPS compliance filing that only shows PG&E's current contractual commitments.~~Sufficient procurement during the second compliance period (2014-2016) that is consistent with the following formula: (.217 * 2014 retail sales) + (.233 * 2015 retail sales) + (.25 * 2016 retail sales).~~<br>• ~~Sufficient procurement during the third compliance period (2017-2020) that is consistent with the following formula: (.27 * 2017 retail sales) + (.29 * 2018 retail sales) + (.31 * 2019 retail sales) + (.33 * 2020 retail sales).~~<br>• ~~33 percent of bundled retail sales in 2021 and all years thereafter.~~ |
| **Shortlisted Projects**<br><br>*From 2014 Solicitation or Bilateral Offer* | • No shortlisted projects are included in PG&E's forecast.<br>• Only executed contracts, or generic deliveries from pre-approved procurement programs (i.e., RAM, Feed-in Tariffs, etc.) are included in PG&E's forecast. |

# Appendix G~~:~~ – Other Modeling Assumptions Informing Quantitative Calculation

| | |
|---|---|
| ~~**Bundled Retail Sales**~~<br>~~*RNS (App. C1)*~~**Green Tariff Shared Renewables (GTSR)** | • ~~Forecasts of retail sales for the first five years of the forecast are generated by PG&E's *Load Forecasting and Research* team every January, and may be updated throughout the year as additional data becomes available.~~<br>• ~~Forecasts of retail sales beyond the first five years are sourced from the latest LTPP standardized planning assumptions, per the May 21, 2014 ALJ Ruling in R.11-05-005 regarding the methodology for calculating the renewable net short.~~<br>• ~~Monthly recorded sales replace forecasts as 2014 progresses.~~If the Commission approves PG&E's pending advice letters to implement GTSR Program, PG&E plans to allocate small amounts of generation from RPS-eligible resources to serve initial GTSR enrollees until new incremental resources procured for the GTSR program are sufficient to meet program needs.<br>• Once the GTSR program is underway, PG&E would also incorporate any GTSR related impacts on its RPS compliance position into future updates to its RNS. |
| ~~**Bundled Retail Sales**~~<br>~~*Alternate RNS (App. C2)*~~ | • ~~Forecasts of retail sales are generated by PG&E's *Load Forecasting and Research* team every January, and may be updated throughout the year as additional data becomes available.~~<br>• ~~Monthly recorded sales replace forecasts as 2014 progresses.~~ |
| **Banking** | • PG&E assumes that (1) Category 3 products that do not exceed applicable portfolio content limits are not deducted from bankable volumes, (2) grandfathered (pre-June 1, 2010) short-term products are bankable, and (3) that banked volumes may be applied in any period onward.<br>• PG&E's accounting is consistent with the direction set forth in Decision 12-06-038. |
| **RPS Sales** | • ~~PG&E's RNS currently only includes~~PG&E will continue to assess the value to its customers of sales ~~from executed contracts in the physical RNS.~~of surplus procurement. Currently, PG&E's renewable net short (RNS), future RPS cost projections and assessment of the current REC market does not lead to an expectation of material projected sales of RECs. However, PG&E will ~~seek to sell any~~consider selling surplus non-bankable~~, surplus~~ RPS~~-eligible~~ volumes~~,~~ and~~, in doing so, PG&E~~ may ~~see opportunities to sell~~consider selling surplus bankable ~~surpluses~~volumes if ~~prices are attractive and~~ it can still maintain an adequate ~~bank.~~Bank and if market conditions are favorable. PG&E will update its ~~physical~~ RNS if it |

| | |
|---|---|
| | executes any such ~~sale~~ agreements. |
| ~~**Green Tariff Shared Renewables (GTSR)**~~ | • ~~If the Commission approves PG&E's pending Application to establish GTSR Program (also known as Green Option) in compliance with implementation of SB 43, PG&E may allocate relatively small portions of the output from the RPS-eligible resources to serve initial GTSR enrollees until new, incremental resources procured for the GTSR commence operation to meet the program demand.~~<br>• ~~PG&E would revise the RNS at that time to account for the reduction in the compliance position.~~ |

## Appendix G: – Other Modeling Assumptions Informing Quantitative Calculation

| Assumptions Related to Forecasted Sales | |
|---|---|
| **Bundled Retail Sales**<br>*RNS (App. C1 and C3)* | • Forecasts of retail sales for the first five years of the forecast were generated by PG&E's *Load Forecasting and Research* team in April 2015, and may be updated throughout the year as additional data becomes available.<br>• Forecasts of retail sales beyond the first five years are sourced from the latest LTPP standardized planning assumptions, per the May 21, 2014 ALJ Ruling in R.11-05-005 regarding the methodology for calculating the renewable net short.<br>• Monthly recorded sales replace forecasts as 2015 progresses. |
| **Bundled Retail Sales**<br><br>*Alternate RNS*<br>*(App. C2 and C4)* | • Forecasts of retail sales were generated by PG&E's *Load Forecasting and Research* team in April 2015, and may be updated throughout the year as additional data becomes available.<br>• Monthly recorded sales replace forecasts as 2015 progresses. |

APPENDIX ~~J~~H

~~Response~~Responses to Renewable Net Short Questions~~ Set Forth in the May 21, 2014 ALJ Ruling~~

~~December 23, 2014~~August 4, 2015

# Appendix ~~J:  Response~~H - Responses to Renewable Net Short Questions ~~Set Forth~~

The following presents PG&E's responses to questions set forth in the May 21, 2014 ~~ALJ~~*Administrative Law Judge's Ruling on Renewable Net Short.*

**RPS Compliance Risk**

**1.  How do current and historical performance of online resources in your RPS portfolio impact future projections of RPS deliveries and your subsequent RNS?**

PG&E considers historical performance of online resources in both of its models.  First, it considers this performance in developing the generation forecast in its deterministic model.  As discussed in Appendix G, future projections of RPS deliveries in the deterministic model are based on ~~contract volumes or~~ a blended three year average output ~~(~~for ~~projects with at least a full calendar year of deliveries, PG&E averages annual contract quantities with available actuals).~~QF contracts.

In addition, ~~in the~~within its stochastic model, PG&E considers RPS generation variability based on historical performance of each resource type~~, calculates the coefficient of variation of each resource type, and then builds a~~.  A probabilistic distribution is built for each resource based on ~~this~~its calculated coefficient of variation.  This captures additional RPS generation variability above and beyond the variances that are captured in the deterministic model.  Section 6.2.~~3~~2 of the RPS Plan describes in more detail how historic generation variability from each resource is used as an input to the stochastic model.

**2.  Do you anticipate any future changes to the current bundled retail sales forecast?  If so, describe how the anticipated changes impact the RNS.**

PG&E's retail sales are impacted by many factors, including weather, economic growth or recession, technological change, energy efficiency, ~~direct access~~DA and ~~community choice aggregation~~CCA participation levels, and distributed generation.  PG&E's most recent Sales Forecast used in the RPS Plan is an April 2015 updated version of the Alternate Scenario Forecast used in the 2014 Bundled Procurement Plan submitted in October 2014 in Rulemaking 13-12-010.  It is important to emphasize that PG&E's Alternative Scenario is a forecast including a number of assumptions regarding events which may or may not occur.  PG&E updates the bundled load forecasts annually to reflect any new events and capture actual load changes.  As described in more detail in Section 6.2.1, PG&E uses its stochastic model to ~~help~~ simulate a range of potential

~~future changes to the current bundled~~ retail sales ~~forecast~~forecasts. Changes in retail sales tend to be variable and persistent, [redacted], particularly over time. However, PG&E's modeling results presented in Section 7 are robust to future changes in sales.

**3. Do you expect curtailment of RPS projects to impact your projected RPS deliveries and subsequent RNS?**

~~Yes, to~~To the extent that ~~output is~~RPS projects are economically bid and do not clear the market, or are curtailed ~~due to~~for system reliability ~~issues or economics~~, PG&E expects that curtailment will impact its RNS. As described in ~~Section~~Sections 6.2.3 and 11, the stochastic model evaluates uncertainty associated with RPS generation variability, including ~~the potential for~~ assumptions of future levels of RPS curtailment.

**4. Are there any significant changes to the success rate of individual RPS projects that impact the RNS?**

~~For the 2014 RPS Plan,~~ PG&E ~~has reduced the assumed~~assumes a volumetric success rate for all executed ~~but-not-yet operational~~ in-development projects in its RPS portfolio ~~from 100% to~~of approximately ~~87~~99% of total contracted volumes. ~~The revised success~~ This rate ~~assumption reflects the addition of projects~~continues its general trend of increasing from 60% in RPS Plans prior to 2012, to ~~the "Closely Watched" list described in Section 6. This has caused a slight increase~~78% in PG&E's ~~RNS in the third compliance period~~2012 RPS Plan, to 100% in PG&E's 2013 RPS Plan, and ~~beyond~~87% in PG&E's 2014 RPS Plan. This success rate is evolving and highly dependent on the nature of PG&E's portfolio and the general conditions in the renewable energy industry. While PG&E has continued to see a general trend towards higher project success rates, its revised success rate assumption (from 87% to 99%) reflects the recent removal of several projects from PG&E's portfolio due to contract termination and an update to the "Closely Watched" category described in Section 6.

In addition, to model the project failure variability inherent in project development, PG&E adds additional success rate assumptions to it stochastic model, which assume that project viability for a yet-to-be-built project is a function of the number of years until its contract start date. These assumptions are used in order to calculate its stochastically-optimized net short~~.~~ (SONS). See the answer to question #5 below for details on these new assumptions.

**5. As projects in development move towards their COD, are there any changes to the expected RPS deliveries? If so, how do these changes impact the RNS?**

Yes. PG&E may adjust the expected delivery volumes in its deterministic model for RPS projects in development for various reasons. For example, counterparties may make adjustments to their project design, such as decreasing total project capacity, which may lead to changes in expected generation. Counterparties may also experience project delays which impact the delivery date for projects, shifting generation volumes further into the future. In extreme cases, as described in Section 6.1.2, PG&E may categorize projects experiencing considerable development challenges as "Closely Watched" and would in those cases reduce the expected delivery volumes from those projects to zero in its deterministic model. Moving a project to the "Closely Watched" category would therefore decrease future delivery volumes and increase the RNS. PG&E has an extensive program for monitoring the development status of RPS-eligible projects, and the deterministic model is updated regularly to reflect any relevant status changes.

In addition, PG&E further reduces its anticipated deliveries from future projects in its stochastic model, as described in more detail in Section 6.2.~~2~~4. To model the project failure variability inherent in project development, PG&E assumes that project viability for a yet-to-be-built project is a function of the number of years until its contract start date. PG&E assigns a probability of project success for new, yet-to-be-built projects equal to [redacted] ~~per year for the number of years remaining until the project is online.~~[redacted]. For~~-~~ example, a project scheduled to come online in five years or more is assumed to have a [redacted] or [redacted] chance of success. This success rate is based on experience, and although PG&E's current existing portfolio of projects may have higher rates of success, the actual success rate for projects in the long-term may be higher or lower. ~~Projects that are re-contracted, in contrast, are modeled at a~~ [redacted] ~~success rate.~~ ~~Appendix~~Appendices F.~~2 lists~~2a and F.2b show PG&E's simulated failure rate and ~~summary statistics~~ for the period ~~2014-2033~~2015-2030 in the 33% RPS and 40% RPS, respectively.

**SUMMARY:**
**COMPARISON OF UNCERTAINTY ASSUMPTIONS**
**BETWEEN PG&E'S DETERMINISTIC AND STOCHASTIC MODELS**

| Reference ~~above~~Above and Uncertainty it Represents | Deterministic Model | Stochastic Model |
|---|---|---|
| **Question #2:** Retail Sales Variability | Uses most recent PG&E bundled retail sales forecast for next 5 years and ~~2010~~2014 LTPP for later years. | ~~Based~~Distribution based on most recent (~~2014~~2015) PG&E bundled retail sales forecast~~, [redacted] standard deviation of the forecast in current year and [redacted] standard deviation of the forecast in future years~~. |
| **Question #4 and #5:** Project Failure Variability | Only turns "off" projects with high likelihood of failure per criteria. "On" projects assumed to deliver at Contract Quantity. | ~~Uses~~ [redacted] Uses [redacted] to model a success rate for all "on" yet-to-be-built projects in the deterministic model. Thus, for a project scheduled to come online in 5 years, the project success rate is [redacted]. This success rate is based on PG&E's experience that the further ahead in the future a project is scheduled to come online, the lower the likelihood of project success. Re-contracted projects are assumed to have a [redacted] success rate. |
| **Question #1~~ and #3~~:** RPS Generation Variability | ~~Assumes 5% reduction (i.e., 95% total success rate) for non-hydro QFs.~~<br>Non-QF projects executed post-2002, 100% of contracted volumes<br>For non-hydro QFs, typically based on an average of the three most recent calendar year deliveries<br><br>Hydro QFs, UOG and IDWA generation projections are updated to reflect the most recent hydro forecast. | Hydro: [redacted] annual variation<br>Wind: [redacted] annual variation<br>Solar: [redacted] annual variation<br><br>Biomass and Geothermal: [redacted] annual variation |
| **Question #3: Curtailment[1]** | None | 33% Scenario: [redacted] of RPS requirement<br>40% Scenario: [redacted] of RPS requirement through 2021, increasing to [redacted] in 2024 and beyond. |

## ~~RECs above the PQR~~

1 These modeling assumptions will not necessarily align with the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance. Please see Section 11 for more information.

**6. What is the appropriate amount of RECs above the PQR to maintain? Please provide a quantitative justification and elaborate on the need for maintaining banked RECs above the PQR.**

As described in Sections 6 and 7, PG&E plans to use a portion of its Bank ~~primarily~~ as a VMOP to manage additional risks and uncertainties accounted for in the stochastic model. PG&E performed a simulation of variability in PG&E's future generation and RPS compliance targets over [redacted] years—i.e., the ~~probabilistic difference between projected~~ amount of RPS generation ~~and projected~~ ("delivery") net of RPS compliance targets~~—~~ ("target")~~—~~and found that a Bank size of ~~approximately~~ [redacted]at least [redacted] GWh is the minimum Bank necessary to maintain a cumulative non-compliance risk ~~over that period~~ of no greater than [redacted]. Under a 40% by 2024 scenario and current market assumptions, PG&E would plan to maintain a minimum Bank level of at least [redacted] GWh. However, because the stochastic model inputs change over time, forecasts of the Bank size will also change, so these estimates should be seen as a point forecast rather than a static target. Please see Section ~~7.2.2~~6 for additional information.

**7. What are your strategies for short-term management (10 years forward) and long-term management (10-20 years forward) of RECs above the PQR? Please discuss any plans to use RECs above the PQR for future RPS compliance and/or to sell RECs above the PQR.**

As described in Sections 6 and 7, PG&E uses its stochastic model to optimize its procurement. This model currently forecasts Bank levels through [redacted], projecting that PG&E's forecasted Bank [redacted]size [redacted] GWh by [redacted]. Under this projection, [redacted] Bank will be maintained as VMOP to manage additional risks and uncertainties associated with managing an RPS portfolio.

In the long-term, PG&E will use RECs above the PQR, as needed, to maintain an adequate Bank, as determined by the deterministic and stochastic model or similar means, in order to manage additional risks and uncertainties.

[redacted]

[redacted]

PG&E's optimization strategy includes consideration of sales of surplus procurement. Consistent with the Commission-approved RNS, PG&E's physical net short and cost projections do not include any future projected sales of bankable contracted deliveries. However, PG&E will consider selling surplus non-bankable RPS volumes and may consider selling surplus bankable RPS volumes if it can still maintain adequate Bank and if market conditions are favorable. As PG&E encounters economic opportunities to sell volumes, PG&E will use the stochastic model to help evaluate whether the proposed sale will increase the cumulative non-compliance risk for [redacted].

**VMOP**

**8. Provide VMOP on both a short-term (10 years forward) and long-term (10-20 years forward) basis. This should include a discussion of all risk factors and a quantitative justification for the amount of VMOP.**

As discussed in Sections 6 and 7, PG&E plans to use a portion of its Bank ~~primarily~~ as a VMOP to manage additional risks and uncertainties accounted for in the stochastic model. [redacted], PG&E believes it would be imprudent to use its entire projected Bank toward meeting the 33% RPS ~~compliance~~ target or 40% RPS scenario, rather than to cover unexpected demand and supply variability and project failure or delay exceeding forecasts from projects not yet under contract. When used as VMOP, the Bank will help to avoid long-term over-procurement above the 33% target, and will thus reduce long-term costs of the RPS Program. ~~Since the model inputs change over time, estimates of the Bank and VMOP are not a static target and will change, so these estimates should be seen as a snapshot in time.~~

**9. Please address the cost-effectiveness of different methods for meeting any projected VMOP procurement need, including application of forecast RECs above the PQR.**

As discussed in Sections 6 and 7, PG&E's stochastic model optimizes its results to ~~suggest a~~inform its RPS procurement strategy, which includes using a portion of the Bank ~~primarily~~ as VMOP, to achieve the lowest cost possible given a specified risk of non-compliance. ~~Given these two constraints, the~~The model suggests a specific level of procurement ~~need~~ and ~~optimal~~resulting Bank ~~size~~usage for each year. PG&E then uses these model results as a tool to guide ~~our~~its actual procurement strategy. While the model provides other possible VMOP usage given a specific level of non-compliance risk, these paths would not be minimum cost under the model's assumptions.

[redacted]

~~Intentional, long-term over-procurement to meet VMOP would not make sense because the Bank would continue to grow, which would be far less cost-effective than PG&E's current strategy. PG&E will continue to evaluate in future RPS planning processes other potential methods to meet additional VMOP need beyond what can be met by the existing Bank).~~

As a general matter, PG&E does not approach RPS procurement and compliance as a speculative enterprise and so has not modeled or otherwise proposed such strategies in this Plan. However, PG&E will consider selling surplus non-bankable RPS volumes in its portfolio and, in doing so, may seek to sell surplus bankable volumes if it can still maintain an adequate Bank and if market conditions are favorable.

**Cost-~~effectiveness~~Effectiveness**

**10. Are there cost-effective opportunities to use banked RECs above the PQR for future RPS compliance in lieu of additional RPS procurement to meet the RNS?**

~~Yes, as~~As discussed in greater detail in Sections 6, 7, and 8 of this Plan, [redacted]. As long as PG&E can continue to maintain an adequate Bank that does not jeopardize PG&E's

ability to manage its non-compliance risk and thus avoid being caught in a "seller's market," where PG&E would face potentially high market prices in order to meet near-term compliance deadlines.~~ As discussed in greater detail in Sections 6, 7, and 8 of this Plan,~~ [redacted]~~.~~

Overall, PG&E can best meet the objective to minimize customer costs when it can thoroughly examine and take advantage of all cost-effective commercial opportunities to purchase or sell RPS-eligible products consistent with its RPS Plan on a going-forward basis, continually adapting to these uncertain variables. PG&E will continue to use the stochastic model to help guide decisions around minimum Bank size needed to maintain PG&E's non-compliance risk of [redacted] for the period of [redacted]. PG&E will then procure any needed incremental volumes ratably over time~~, as it has proposed to do in this 2014 Plan.~~.

**11. How does your current RNS fit within the regulatory limitations for PCCs? Are there opportunities to optimize your portfolio by procuring RECs across different PCCs?**

PG&E's current RPS portfolio consists of primarily Category 0 and 1 RECs. Category 3 products are a limited, but potentially important, part of PG&E's procurement strategy as they may provide a low-cost compliance option for PG&E's customers while at the same time potentially mitigating integration and other operational challenges associated with incremental procurement from typical Category 1 or Category 2 procurement.~~ If PG&E decides to execute Category 3 transactions as part of the 2014 RPS RFO, this procurement would make up a very small proportion of PG&E's overall 2014 Solicitation target of 1,600 GWh per year.~~ [redacted]

~~PG&E recently sought Commission approval to procure small volumes of Category 3 RECs in order to minimize cost impacts of the RPS Program and to optimize PG&E's portfolio consistent with statutory requirements.~~[2] ~~A majority of Commissioners voted on May 1, 2014 to reject those transactions. PG&E's ability to purchase Category 3 products will influence its decision to sell excess banked procurement in the future. These sales could provide a cost saving opportunity for customers as the sale price for excess banked procurement may exceed the replacement cost using Category 3 RECs.~~

While PG&E seeks opportunities across all product categories to procure the most cost-effective resources to achieve the RPS requirements, the existing restrictions on

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[2] ~~*See* PG&E's Advice Letters 4299-E, 4300-E, and 4301-E.~~

banking of excess procurement limit PG&E's ability to fully optimize its portfolio. Under the current RPS rules, short-term contracts cannot count towards excess procurement eligible for banking toward a future RPS compliance period. The result is that any entity that has excess procurement during a particular compliance period is effectively restricted from procuring short-term contracts during that compliance period. Only when an entity does not exceed its compliance period target, is it able to count short-term procurement towards meeting its targets.

PG&E currently maintains a bank in order to help mitigate procurement and load variability. Thus, the inability for short-term contracts to contribute to the bank restricts our mitigation strategy. Allowing the unrestricted banking of all RPS products, including those associated with short-term contracts, would enable PG&E to better manage risks and achieve cost-savings for our customers.

# APPENDIX B

## Project Development Status Update

August 4, 2015

# Appendix B - Project Development Status Update

| Line No. | IOU ID | Project Name | Primary Developer | Technology Type | Contract Capacity (MW) | Expected Energy (GWh) | Energy Delivery Status | Vintage | CPUC Approval Status | Financing Status | Permit Status | Guaranteed Construction Start Date | Expected or Actual Construction Start Date | Construction Status | Status of Interconnection Agreement | Guaranteed COD | Expected or Actual COD |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 33R255 | Kansas | Dominion Solar Holdings, Inc. | Solar Photovoltaic | 20 | 47 | [redacted] | New | CPUC Approved | [redacted] | Complete | [redacted] | [redacted] | Complete | Complete | 12/31/2016 | 12/26/2014 |
| 2 | 33R279 | Alamo Solar, LLC | Dominion Solar Holdings, Inc. | Solar Photovoltaic | 20 | 50 | [redacted] | New | CPUC Approved | [redacted] | Complete | N/A | [redacted] | Complete | Complete | 5/20/2015 | 5/20/2015 |
| 3 | 33R291 | Shafter Solar | NextEra Energy Resources | Solar Photovoltaic | 20 | 53 | [redacted] | New | CPUC Approved | [redacted] | Complete | N/A | [redacted] | Complete | Complete | 10/10/2015 | 6/3/2015 |
| 4 | 33R148 | North Star Solar 1 | Southern Renewable Partnerships, LLC | Solar Photovoltaic | 60 | 136 | [redacted] | New | CPUC Approved | [redacted] | Complete | [redacted] | [redacted] | [redacted] | Complete | 6/20/2015 | [redacted] |
| 5 | 33R278 | Columbia Solar Energy, LLC | Hanergy Holding America, Inc. | Solar Photovoltaic | 19 | 41 | [redacted] | New | CPUC Approved | [redacted] | Complete | N/A | [redacted] | [redacted] | Complete | 5/20/2015 | [redacted] |
| 6 | 33R324 | Woodmere Solar Farm | sPower | Solar Photovoltaic | 15 | 33 | [redacted] | New | CPUC Approved | [redacted] | Complete | N/A | [redacted] | [redacted] | Complete | 2/3/2016 | [redacted] |
| 7 | 33R322 | Rising Tree Wind Farm II LLC | EDP Renewables North America LLC | Wind | 20 | 69 | [redacted] | New | CPUC Approved | [redacted] | Complete | N/A | [redacted] | Complete | Complete | 2/3/2016 | [redacted] |
| 8 | 33R254 | SPI Biomass Portfolio | Sierra Pacific Industries | Biomass | 58 | 346 | [redacted] | Existing / New | CPUC Approved | [redacted] | Complete | [redacted] | [redacted] | Complete | Complete | 9/23/2015 | [redacted] |
| 9 | 33R292 | Morelos Del Sol | Gestamp Asetym Solar North America | Solar Photovoltaic | 15 | 33 | [redacted] | New | CPUC Approved | [redacted] | [redacted] | N/A | [redacted] | [redacted] | Complete | 12/10/2015 | [redacted] |
| 10 | 33R287 | Sand Hill Wind, LLC | Ogin, Inc. | Wind | 20 | 44 | [redacted] | Repowered | CPUC Approved | [redacted] | Complete | N/A | [redacted] | [redacted] | [redacted] | 12/10/2015 | [redacted] |
| 11 | 33R326 | Blackwell Solar Park, LLC | Frontier Renewables LLC | Solar Photovoltaic | 20 | 48 | [redacted] | New | CPUC Approved | [redacted] | Complete | N/A | [redacted] | [redacted] | Complete | 2/3/2016 | [redacted] |
| 12 | 33R367 | Altech III | Ogin, Inc. | Wind | 20 | 53 | [redacted] | Repowered | CPUC Approved | [redacted] | [redacted] | N/A | N/A (Existing) | [redacted] | [redacted] | 11/1/2016 | [redacted] |
| 13 | 33R375 | Westside Solar, LLC | Nextera Energy Resources, LLC and its subsidiary Aries Solar Holding, LLC | Solar Photovoltaic | 20 | 55 | [redacted] | New | CPUC Approved | [redacted] | Complete | N/A | [redacted] | [redacted] | Complete | 5/30/2017 | [redacted] |
| 14 | 33R329 | Diablo Winds (2) | NextEra Energy Resources, LLC | Wind | 18 | 62 | [redacted] | Existing | CPUC Approved | [redacted] | Complete | N/A | N/A (Existing) | Complete | Complete | 7/1/2016 | [redacted] |
| 15 | 33R361 | Maricopa West Solar PV 2, LLC | E.ON Climate and Renewables North America, LLC | Solar Photovoltaic | 20 | 55 | [redacted] | New | CPUC Approved | [redacted] | Complete | N/A | [redacted] | [redacted] | [redacted] | 1/17/2017 | [redacted] |
| 16 | 33R257 | Cuyama Solar Array | First Solar, Inc. | Solar Photovoltaic | 40 | 104 | [redacted] | New | CPUC Approved | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | Complete | 12/31/2019 | [redacted] |
| 17 | 33R259 | Henrietta Solar | SunPower | Solar Photovoltaic | 100 | 244 | [redacted] | New | CPUC Approved | [redacted] | Complete | [redacted] | [redacted] | [redacted] | Complete | 10/1/2016 | [redacted] |
| 18 | 33R362 | Portal Ridge Solar C Project | First Solar, Inc. | Solar Photovoltaic | 11 | 30 | [redacted] | New | CPUC Approved | [redacted] | Complete | N/A | [redacted] | [redacted] | Complete | 1/17/2017 | [redacted] |
| 19 | 33R374 | CED Corcoran Solar 3, LLC | Con Edison Development | Solar Photovoltaic | 20 | 49 | [redacted] | New | CPUC Approved | [redacted] | [redacted] | N/A | [redacted] | [redacted] | Complete | 5/30/2017 | [redacted] |
| 20 | 33R364 | Sunray 20 | Cogentrix Solar Holdings, LLC | Solar Photovoltaic | 20 | 51 | [redacted] | New | CPUC Approved | [redacted] | Complete | N/A | [redacted] | [redacted] | [redacted] | 1/17/2017 | [redacted] |
| 21 | 33R133 | Potrero Hills Landfill | DTE Biomass Energy | Biogas Generation | 8 | 56 | [redacted] | New | CPUC Approved | [redacted] | Complete | [redacted] | [redacted] | [redacted] | Complete | 12/6/2016 | [redacted] |
| 22 | 33R376 | Aspiration Solar G LLC | FTP Solar LLC | Solar Photovoltaic | 9 | 23 | [redacted] | New | CPUC Approved | [redacted] | [redacted] | N/A | [redacted] | [redacted] | Complete | 3/23/2017 | [redacted] |
| 23 | 33R344 | California Flats Solar Project | First Solar, Inc. | Solar Photovoltaic | 150 | 381 | [redacted] | New | CPUC Approved | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | Complete | 12/31/2018 | [redacted] |
| 24 | 33R330 | RE Astoria LLC | Recurrent Energy | Solar Photovoltaic | 100 | 298 | [redacted] | New | CPUC Approved | [redacted] | Complete | [redacted] | [redacted] | [redacted] | Complete | 1/3/2019 | [redacted] |
| 25 | 33R363 | SR Solis Oro Loma Teresina, LLC- Project A | Con Edison Development | Solar Photovoltaic | 10 | 26 | [redacted] | New | CPUC Approved | [redacted] | [redacted] | N/A | [redacted] | [redacted] | Complete | 1/17/2017 | [redacted] |
| 26 | 33R366 | SR Solis Oro Loma Teresina, LLC- Project B | Con Edison Development | Solar Photovoltaic | 10 | 26 | [redacted] | New | CPUC Approved | [redacted] | [redacted] | N/A | [redacted] | [redacted] | Complete | 1/17/2017 | [redacted] |
| 27 | 33R365 | SR Solis Rocket, LLC - Project A | Con Edison Development | Solar Photovoltaic | 8 | 20 | [redacted] | New | CPUC Approved | [redacted] | [redacted] | N/A | [redacted] | [redacted] | Complete | 1/17/2017 | [redacted] |
| 28 | 33R368 | SR Solis Rocket, LLC - Project B | Con Edison Development | Solar Photovoltaic | 8 | 20 | [redacted] | New | CPUC Approved | [redacted] | [redacted] | N/A | [redacted] | [redacted] | Complete | 1/17/2017 | [redacted] |
| 29 | 33R258 | Blackwell Solar | First Solar, Inc. | Solar Photovoltaic | 12 | 28 | [redacted] | New | CPUC Approved | [redacted] | Complete | [redacted] | [redacted] | Complete | Complete | 12/31/2019 | [redacted] |
| 30 | 33R256 | Lost Hills Solar | First Solar, Inc. | Solar Photovoltaic | 20 | 47 | [redacted] | New | CPUC Approved | [redacted] | Complete | [redacted] | [redacted] | Complete | Complete | 12/31/2019 | [redacted] |
| 31 | 33R343 | Midway Solar Farm I | Solar Frontier Americas Holding, LLC | Solar Photovoltaic | 50 | 119 | [redacted] | New | CPUC Approved | [redacted] | Complete | [redacted] | [redacted] | [redacted] | Complete | 6/1/2020 | [redacted] |

# APPENDIX C.1a

# Renewable Net Short Calculations – 33% RPS Target

August 4, 2015

# Appendix C.1a - Renewable Net Short Calculations - 33% RPS Target

## Net Short Calculation Using PG&E Bundled Retail Sales Forecast In Near Term (2015 - 2019) and LTPP Methodology (2020 - 2035)

| Variable | Calculation | Item | Deficit from RPS prior to Reporting Year | 2011 Actuals | 2012 Actuals | 2013 Actuals | 2011-2013 | 2014 Actuals | 2015 Forecast | 2016 Forecast | 2014-2016 | 2017 Forecast | 2018 Forecast | 2019 Forecast | 2020 Forecast | 2017-2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Forecast Year | | - | - | - | CP1 | - | - | - | CP2 | - | - | - | - | CP3 |
| | | **Annual RPS Requirement** | | | | | | | | | | | | | | |
| A | | Bundled Retail Sales Forecast (LTPP)[1] | | 74,864 | 76,205 | 75,705 | 226,774 | 74,547 | 71,183 | 70,870 | 216,599 | [redacted] | 64,957 | 62,381 | 79,463 | [redacted] |
| B | | RPS Procurement Quantity Requirement (%) | | 20.0% | 20.0% | 20.0% | 20.0% | 21.7% | 23.3% | 25.0% | 23.3% | 27.0% | 29.0% | 31.0% | 33.0% | 30.0% |
| C | A*B | **Gross RPS Procurement Quantity Requirement (GWh)** | | 14,973 | 15,241 | 15,141 | 45,355 | 16,177 | 16,586 | 17,717 | 50,480 | [redacted] | 18,837 | 19,338 | 26,223 | [redacted] |
| D | | Voluntary Margin of Over-procurement[2] | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| E | C+D | **Net RPS Procurement Need (GWh)** | | 14,973 | 15,241 | 15,141 | 45,355 | 16,177 | 16,586 | 17,717 | 50,480 | [redacted] | 18,837 | 19,338 | 26,223 | [redacted] |
| | | **RPS-Eligible Procurement** | | | | | | | | | | | | | | |
| Fa | | Risk-Adjusted RECs from Online Generation[10] | | 14,699 | 14,513 | 17,212 | 46,424 | 20,206 | 22,092 | 21,967 | 64,265 | 21,693 | 19,728 | 19,038 | 18,198 | 78,656 |
| Faa | | Forecast Failure Rate for Online Generation (%) | | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Fb | | Risk-Adjusted RECs from RPS Facilities in Development[11] | | - | - | - | - | - | 363 | 943 | 1,306 | 1,981 | 2,113 | 2,518 | 2,702 | 9,314 |
| Fbb | | Forecast Failure Rate for RPS Facilities in Development (%) | | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 5.5% | 3.2% | 2.9% | 1.5% | 1.4% | 1.2% | 1.1% | 1.3% |
| Fc | | Pre-Approved Generic RECs | | - | - | - | - | - | - | 19 | 19 | 179 | 672 | 1,035 | 1,123 | 3,009 |
| Fd | | Executed REC Sales | | - | - | (142) | (142) | (50) | - | - | (50) | - | - | - | - | - |
| F | Fa + Fb +Fc - Fd | Total RPS Eligible Procurement (GWh)[9] | | 14,699 | 14,513 | 17,069 | 46,281 | 20,156 | 22,455 | 22,930 | 65,541 | 23,853 | 22,512 | 22,590 | 22,023 | 90,979 |
| F0 | | Category 0 RECs | | 14,637 | 13,035 | 14,149 | 41,821 | 16,886 | 18,251 | 18,053 | 53,190 | 17,756 | 15,822 | 15,137 | 14,297 | 63,013 |
| F1 | | Category 1 RECs | | 62 | 1,478 | 2,921 | 4,461 | 3,270 | 4,204 | 4,877 | 12,351 | 6,097 | 6,690 | 7,454 | 7,726 | 27,966 |
| F2 | | Category 2 RECs | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| F3 | | Category 3 RECs | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | **Gross RPS Position (Physical Net Short)** | | | | | | | | | | | | | | |
| Ga | F-E | **Annual Gross RPS Position (GWh)** | | (274) | (728) | 1,928 | 926 | 3,979 | 5,869 | 5,212 | 15,061 | [redacted] | 3,675 | 3,252 | (4,200) | [redacted] |
| Gb | F/A | **Annual Gross RPS Position (%)** | | 19.6% | 19.0% | 22.5% | 20.4% | 27.0% | 31.5% | 32.4% | 30.3% | [redacted] | 34.7% | 36.2% | 27.7% | [redacted] |
| | | **Application of Bank** | | | | | | | | | | | | | | |
| Ha | H - Hc (from previous year) | Existing Banked RECs above the PQR[3,4] | | - | (274) | (1,033) | - | 861 | | | | | | | | |
| Hb | | RECs above the PQR added to Bank | | (274) | (728) | 1,928 | 926 | 3,979 | 5,869 | 5,212 | 15,061 | [redacted] | 3,675 | 3,252 | - | 12,465 |
| Hc | | Non-bankable RECs above the PQR | | - | 31 | 34 | 65 | 26 | 22 | 71 | 119 | 83 | - | - | - | 83 |
| H | Ha+Hb | Gross Balance of RECs above the PQR | | (274) | (1,002) | 895 | 926 | 4,840 | | | | | | | | |
| Ia | | Planned Application of RECs above the PQR towards RPS Compliance[5] | | - | - | - | - | | | | | | | | | |
| Ib | | Planned Sales of RECs above the PQR[6] | | - | - | - | - | | | | | | | | | |
| J | H-Ia-Ib | Net Balance of RECs above the PQR[3] | | (274) | (1,002) | 895 | 926 | | | | | | | | | |
| J0 | | Category 0 RECs | | - | - | - | - | | | | | | | | | |
| J1 | | Category 1 RECs | | - | - | 895 | 895 | | | | | | | | | |
| J2 | | Category 2 RECs | | - | - | - | - | | | | | | | | | |
| | | **Expiring Contracts** | | | | | | | | | | | | | | |
| K | | RECs from Expiring RPS Contracts[12] | | N/A | N/A | N/A | N/A | - | 0.4 | 518 | 518 | 1,011 | 1,642 | 3,866 | 4,732 | 11,250 |
| | | **Net RPS Position (Optimized Net Short)** | | | | | | | | | | | | | | |
| La | Ga + Ia – Ib – Hc | **Annual Net RPS Position after Bank Optimization (GWh)**[7] | | (274) | (759) | 1,894 | 861 | | | | | | | | | |
| Lb | (F + Ia – Ib – Hc)/A | **Annual Net RPS Position after Bank Optimization (%)**[7,8] | | 19.6% | 19.0% | 22.5% | 20.4% | | | | | | | | | |

| Variable | 2021 Forecast | 2022 Forecast | 2023 Forecast | 2024 Forecast | 2025 Forecast | 2026 Forecast | 2027 Forecast | 2028 Forecast | 2029 Forecast | 2030 Forecast | 2031 Forecast | 2032 Forecast | 2033 Forecast | 2034 Forecast | 2035 Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| A | 79,938 | 80,411 | 80,666 | 80,841 | 81,057 | 81,273 | 81,490 | 81,708 | 81,926 | 82,145 | 82,364 | 82,584 | 82,804 | 83,025 | 83,247 |
| B | 33.0% | 33.0% | 33.0% | 33.0% | 33.0% | 33.0% | 33.0% | 33.0% | 33.0% | 33.0% | 33.0% | 33.0% | 33.0% | 33.0% | 33.0% |
| C | 26,380 | 26,536 | 26,620 | 26,678 | 26,749 | 26,820 | 26,892 | 26,964 | 27,036 | 27,108 | 27,180 | 27,253 | 27,325 | 27,398 | 27,471 |
| D | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| E | 26,380 | 26,536 | 26,620 | 26,678 | 26,749 | 26,820 | 26,892 | 26,964 | 27,036 | 27,108 | 27,180 | 27,253 | 27,325 | 27,398 | 27,471 |
| Fa | 17,772 | 15,361 | 15,028 | 14,760 | 14,648 | 14,084 | 13,842 | 13,791 | 13,235 | 13,170 | 12,807 | 12,280 | 11,060 | 10,060 | 9,276 |
| Faa | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Fb | 2,737 | 2,725 | 2,713 | 2,707 | 2,690 | 2,679 | 2,667 | 2,661 | 2,644 | 2,633 | 2,605 | 2,230 | 2,182 | 1,888 | 1,498 |
| Fbb | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.2% | 1.3% | 1.4% | 0.6% |
| Fc | 1,202 | 1,219 | 1,216 | 1,216 | 1,211 | 1,208 | 1,205 | 1,205 | 1,199 | 1,197 | 1,194 | 1,194 | 1,188 | 1,186 | 1,183 |
| Fd | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| F | 21,711 | 19,305 | 18,957 | 18,683 | 18,549 | 17,971 | 17,714 | 17,657 | 17,078 | 17,000 | 16,605 | 15,704 | 14,430 | 13,134 | 11,956 |
| F0 | 13,889 | 11,501 | 11,207 | 10,982 | 10,898 | 10,345 | 10,112 | 10,065 | 9,538 | 9,493 | 9,178 | 9,082 | 8,457 | 7,823 | 7,376 |
| F1 | 7,822 | 7,805 | 7,750 | 7,701 | 7,651 | 7,626 | 7,602 | 7,592 | 7,540 | 7,507 | 7,427 | 6,622 | 5,973 | 5,311 | 4,580 |
| F2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| F3 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Ga | (4,668) | (7,230) | (7,662) | (7,995) | (8,200) | (8,849) | (9,178) | (9,306) | (9,957) | (10,108) | (10,575) | (11,548) | (12,895) | (14,265) | (15,515) |
| Gb | 27.2% | 24.0% | 23.5% | 23.1% | 22.9% | 22.1% | 21.7% | 21.6% | 20.8% | 20.7% | 20.2% | 19.0% | 17.4% | 15.8% | 14.4% |
| Hb | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Hc | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| K | 5,071 | 7,433 | 7,728 | 8,014 | 8,028 | 8,555 | 8,760 | 8,818 | 9,286 | 9,315 | 9,656 | 10,564 | 11,728 | 12,962 | 14,090 |

General Table Notes: Values are shown in GWhs. Fields in grey are protected as Confidential under CPUC Confidentiality Rules.

**(1) (Row A) LTPP sales forecast is not representative of PG&E's actual retail sales. Forecasts of retail sales for the first five years of the forecast were generated by PG&E's Load Forecasting and Research team at the beginning of each year, and may be updated throughout the year as additional data becomes available.**

**(2) (Row D) As a portion of the Bank will be used as VMOP, Row D will remain zero. See 2015 RPS Plan for a description of PG&E's VMOP.**

**(3) (Rows Ha and J) As PG&E's Alternative RNS incorporates additional risk-adjustments to the results from the Physical Net Short, the Bank sizes indicated in Rows Ha and J appear larger than they are in Rows Ha and J of the Alternative RNS, which shows the stochastically-adjusted Bank size.**

**(4) (Rows Ha) At the beginning of each compliance period Row Ha subtracts previous compliance non-bankable volumes from the previous compliance period net balance of RECs. For example, the 2021 forecast for Row Ha is equivalent to the Row J in CP3 minus Row Hc in CP3.**

**(5) (Row Ia) The results in Ia are only applicable within the context of the stochastic model. Please see the Alternative RNS for the application of the bank.**

**(6) (Row Ib) The purpose of the planned sales is to minimize the non-bankable volumes, but the actual sales could be a combination of bankable and non-bankable volumes.**

**(7) (Rows La and Lb) Rows La and Lb incorrectly subtract the non-bankable volumes. Although these volumes can not be carried forward, per Decision 12-06-038, these volumes could be used towards meeting compliance in the current period. Therefore, the non-bankable volumes should be included in the Annual Net RPS Position after Bank Optimization.**

**(8) (Row Lb) Row Lb incorrectly calculates the Annual Net RPS Position after Bank Optimization. PG&E has changed the formula in the Alternative RNS to (Ga+Ia-Ib+E)/A in order to express these values in a comparable way to the Physical Net Short (%) in Row Gb.**

**(9) (Row F) Row F has subtracted 134 GWh of RECs associated with 2011 generation from the Hay Canyon Wind Facility and the Nine Canyon Wind Phase 3. These RECs are not being used for RPS compliance because they were not retired within the RPS statute's 36-month REC retirement deadline.**

**(10) (Row Fa) "Online Generation" includes forecasted volumes from replacement contracts (i.e. ReMAT contracts replacing QF contracts) for facilities that are already online.**

**(11) (Row Fb) "In Development" includes forecasted volumes from phase-in projects. This is consistent with labeling in the RPS Database (which labels phase-in projects as "In Development" under "Overall Project Status").**

**(12) (Row K) Row K now includes only expiring volumes from contracts as of April 30, 2015.**

*Stochastic Results in Rows Ga-Lb reflect a April 30, 2015 stochastic modeling vintage.

†Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans, Rulemaking ("R.") 13-12-010, filed December 19, 2013.

# APPENDIX C.1b

# Renewable Net Short Calculations – 40% RPS Scenario

August 4, 2015

# Appendix C.1b - Renewable Net Short Calculations - 40% RPS Scenario

## Net Short Calculation Using PG&E Bundled Retail Sales Forecast In Near Term (2015 - 2019) and LTPP Methodology (2020 - 2035)

| Variable | Calculation | Item | Deficit from RPS prior to Reporting Year | 2011 Actuals | 2012 Actuals | 2013 Actuals | 2011-2013 | 2014 Actuals | 2015 Forecast | 2016 Forecast | 2014-2016 | 2017 Forecast | 2018 Forecast | 2019 Forecast | 2020 Forecast | 2017-2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Forecast Year | | - | - | - | CP1 | - | - | - | CP2 | - | - | - | - | CP3 |
| | | **Annual RPS Requirement** | | | | | | | | | | | | | | |
| A | | Bundled Retail Sales Forecast (LTPP)[1] | | 74,864 | 76,205 | 75,705 | 226,774 | 74,547 | 71,183 | 70,870 | 216,599 | [redacted] | 64,957 | 62,381 | 79,463 | [redacted] |
| B | | RPS Procurement Quantity Requirement (%) | | 20.0% | 20.0% | 20.0% | 20.0% | 21.7% | 23.3% | 25.0% | 23.3% | 27.0% | 29.0% | 31.0% | 33.0% | 30.0% |
| C | A*B | **Gross RPS Procurement Quantity Requirement (GWh)** | | 14,973 | 15,241 | 15,141 | 45,355 | 16,177 | 16,586 | 17,717 | 50,480 | [redacted] | 18,837 | 19,338 | 26,223 | [redacted] |
| D | | Voluntary Margin of Over-procurement[2] | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| E | C+D | **Net RPS Procurement Need (GWh)** | | 14,973 | 15,241 | 15,141 | 45,355 | 16,177 | 16,586 | 17,717 | 50,480 | [redacted] | 18,837 | 19,338 | 26,223 | [redacted] |
| | | **RPS-Eligible Procurement** | | | | | | | | | | | | | | |
| Fa | | Risk-Adjusted RECs from Online Generation[10] | | 14,699 | 14,513 | 17,212 | 46,424 | 20,206 | 22,092 | 21,967 | 64,265 | 21,693 | 19,728 | 19,038 | 18,198 | 78,656 |
| Faa | | Forecast Failure Rate for Online Generation (%) | | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Fb | | Risk-Adjusted RECs from RPS Facilities in Development[11] | | - | - | - | - | - | 363 | 943 | 1,306 | 1,981 | 2,113 | 2,518 | 2,702 | 9,314 |
| Fbb | | Forecast Failure Rate for RPS Facilities in Development (%) | | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 5.5% | 3.2% | 2.9% | 1.5% | 1.4% | 1.2% | 1.1% | 1.3% |
| Fc | | Pre-Approved Generic RECs | | - | - | - | - | - | - | 19 | 19 | 179 | 672 | 1,035 | 1,123 | 3,009 |
| Fd | | Executed REC Sales | | - | - | (142) | (142) | (50) | - | - | (50) | - | - | - | - | - |
| F | Fa + Fb +Fc - Fd | Total RPS Eligible Procurement (GWh)[9] | | 14,699 | 14,513 | 17,069 | 46,281 | 20,156 | 22,455 | 22,930 | 65,541 | 23,853 | 22,512 | 22,590 | 22,023 | 90,979 |
| F0 | | Category 0 RECs | | 14,637 | 13,035 | 14,149 | 41,821 | 16,886 | 18,251 | 18,053 | 53,190 | 17,756 | 15,822 | 15,137 | 14,297 | 63,013 |
| F1 | | Category 1 RECs | | 62 | 1,478 | 2,921 | 4,461 | 3,270 | 4,204 | 4,877 | 12,351 | 6,097 | 6,690 | 7,454 | 7,726 | 27,966 |
| F2 | | Category 2 RECs | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| F3 | | Category 3 RECs | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | **Gross RPS Position (Physical Net Short)** | | | | | | | | | | | | | | |
| Ga | F-E | **Annual Gross RPS Position (GWh)** | | (274) | (728) | 1,928 | 926 | 3,979 | 5,869 | 5,212 | 15,061 | [redacted] | 3,675 | 3,252 | (4,200) | [redacted] |
| Gb | F/A | **Annual Gross RPS Position (%)** | | 19.6% | 19.0% | 22.5% | 20.4% | 27.0% | 31.5% | 32.4% | 30.3% | [redacted] | 34.7% | 36.2% | 27.7% | [redacted] |
| | | **Application of Bank** | | | | | | | | | | | | | | |
| Ha | H - Hc (from previous year) | Existing Banked RECs above the PQR[3,4] | | - | (274) | (1,033) | - | 861 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Hb | | RECs above the PQR added to Bank | | (274) | (728) | 1,928 | 926 | 3,979 | 5,869 | 5,212 | 15,061 | [redacted] | 3,675 | 3,252 | - | 12,465 |
| Hc | | Non-bankable RECs above the PQR | | - | 31 | 34 | 65 | 26 | 22 | 71 | 119 | 83 | - | - | - | 83 |
| H | Ha+Hb | Gross Balance of RECs above the PQR | | (274) | (1,002) | 895 | 926 | 4,840 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Ia | | Planned Application of RECs above the PQR towards RPS Compliance[5] | | - | - | - | - | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Ib | | Planned Sales of RECs above the PQR[6] | | - | - | - | - | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| J | H-Ia-Ib | Net Balance of RECs above the PQR[3] | | (274) | (1,002) | 895 | 926 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| J0 | | Category 0 RECs | | - | - | - | - | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| J1 | | Category 1 RECs | | - | - | 895 | 895 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| J2 | | Category 2 RECs | | - | - | - | - | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | **Expiring Contracts** | | | | | | | | | | | | | | |
| K | | RECs from Expiring RPS Contracts[12] | | N/A | N/A | N/A | N/A | - | 0.4 | 518 | 518 | 1,011 | 1,642 | 3,866 | 4,732 | 11,250 |
| | | **Net RPS Position (Optimized Net Short)** | | | | | | | | | | | | | | |
| La | Ga + Ia – Ib – Hc | **Annual Net RPS Position after Bank Optimization (GWh)[7]** | | (274) | (759) | 1,894 | 861 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Lb | (F + Ia – Ib – Hc)/A | **Annual Net RPS Position after Bank Optimization (%)[7,8]** | | 19.6% | 19.0% | 22.5% | 20.4% | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

| Variable | 2021 Forecast | 2022 Forecast | 2023 Forecast | 2024 Forecast | 2025 Forecast | 2026 Forecast | 2027 Forecast | 2028 Forecast | 2029 Forecast | 2030 Forecast | 2031 Forecast | 2032 Forecast | 2033 Forecast | 2034 Forecast | 2035 Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (Forecast Year) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| A | 79,938 | 80,411 | 80,666 | 80,841 | 81,057 | 81,273 | 81,490 | 81,708 | 81,926 | 82,145 | 82,364 | 82,584 | 82,804 | 83,025 | 83,247 |
| B | 33.0% | 37.0% | 37.0% | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% |
| C | 26,380 | 29,752 | 29,846 | 32,336 | 32,423 | 32,509 | 32,596 | 32,683 | 32,770 | 32,858 | 32,946 | 33,034 | 33,122 | 33,210 | 33,299 |
| D | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| E | 26,380 | 29,752 | 29,846 | 32,336 | 32,423 | 32,509 | 32,596 | 32,683 | 32,770 | 32,858 | 32,946 | 33,034 | 33,122 | 33,210 | 33,299 |
| Fa | 17,772 | 15,361 | 15,028 | 14,760 | 14,648 | 14,084 | 13,842 | 13,791 | 13,235 | 13,170 | 12,807 | 12,280 | 11,060 | 10,060 | 9,276 |
| Faa | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Fb | 2,737 | 2,725 | 2,713 | 2,707 | 2,690 | 2,679 | 2,667 | 2,661 | 2,644 | 2,633 | 2,605 | 2,230 | 2,182 | 1,888 | 1,498 |
| Fbb | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.2% | 1.3% | 1.4% | 0.6% |
| Fc | 1,202 | 1,219 | 1,216 | 1,216 | 1,211 | 1,208 | 1,205 | 1,205 | 1,199 | 1,197 | 1,194 | 1,194 | 1,188 | 1,186 | 1,183 |
| Fd | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| F | 21,711 | 19,305 | 18,957 | 18,683 | 18,549 | 17,971 | 17,714 | 17,657 | 17,078 | 17,000 | 16,605 | 15,704 | 14,430 | 13,134 | 11,956 |
| F0 | 13,889 | 11,501 | 11,207 | 10,982 | 10,898 | 10,345 | 10,112 | 10,065 | 9,538 | 9,493 | 9,178 | 9,082 | 8,457 | 7,823 | 7,376 |
| F1 | 7,822 | 7,805 | 7,750 | 7,701 | 7,651 | 7,626 | 7,602 | 7,592 | 7,540 | 7,507 | 7,427 | 6,622 | 5,973 | 5,311 | 4,580 |
| F2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| F3 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Ga | (4,668) | (10,447) | (10,889) | (13,653) | (13,874) | (14,539) | (14,883) | (15,026) | (15,692) | (15,858) | (16,340) | (17,329) | (18,691) | (20,077) | (21,342) |
| Gb | 27.2% | 24.0% | 23.5% | 23.1% | 22.9% | 22.1% | 21.7% | 21.6% | 20.8% | 20.7% | 20.2% | 19.0% | 17.4% | 15.8% | 14.4% |
| Ha | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Hb | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Hc | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| H | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Ia | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Ib | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| J | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| J0 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| J1 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| J2 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| K | 5,071 | 7,433 | 7,728 | 8,014 | 8,028 | 8,555 | 8,760 | 8,818 | 9,286 | 9,315 | 9,656 | 10,564 | 11,728 | 12,962 | 14,090 |
| La | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Lb | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

General Table Notes: Values are shown in GWhs. Fields in grey are protected as Confidential under CPUC Confidentiality Rules.

**(1) (Row A) LTPP sales forecast is not representative of PG&E's actual retail sales. Forecasts of retail sales for the first five years of the forecast were generated by PG&E's Load Forecasting and Research team at the beginning of each year, and may be updated throughout the year as additional data becomes available.**

**(2) (Row D) As a portion of the Bank will be used as VMOP, Row D will remain zero. See 2015 RPS Plan for a description of PG&E's VMOP.**

**(3) (Rows Ha and J) As PG&E's Alternative RNS incorporates additional risk-adjustments to the results from the Physical Net Short, the Bank sizes indicated in Rows Ha and J appear larger than they are in Rows Ha and J of the Alternative RNS, which shows the stochastically-adjusted Bank size.**

**(4) (Rows Ha) At the beginning of each compliance period Row Ha subtracts previous compliance non-bankable volumes from the previous compliance period net balance of RECs. For example, the 2021 forecast for Row Ha is equivalent to the Row J in CP3 minus Row Hc in CP3.**

**(5) (Row Ia) The results in Ia are only applicable within the context of the stochastic model. Please see the Alternative RNS for the application of the bank.**

**(6) (Row Ib) The purpose of the planned sales is to minimize the non-bankable volumes, but the actual sales could be a combination of bankable and non-bankable volumes.**

**(7) (Rows La and Lb) Rows La and Lb incorrectly subtract the non-bankable volumes. Although these volumes can not be carried forward, per Decision 12-06-038, these volumes could be used towards meeting compliance in the current period. Therefore, the non-bankable volumes should be included in the Annual Net RPS Position after Bank Optimization.**

**(8) (Row Lb) Row Lb incorrectly calculates the Annual Net RPS Position after Bank Optimization. PG&E has changed the formula in the Alternative RNS to (Ga+Ia-Ib+E)/A in order to express these values in a comparable way to the Physical Net Short (%) in Row Gb.**

**(9) (Row F) Row F has subtracted 134 GWh of RECs associated with 2011 generation from the Hay Canyon Wind Facility and the Nine Canyon Wind Phase 3. These RECs are not being used for RPS compliance because they were not retired within the RPS statute's 36-month REC retirement deadline.**

**(10) (Row Fa) "Online Generation" includes forecasted volumes from replacement contracts (i.e. ReMAT contracts replacing QF contracts) for facilities that are already online.**

**(11) (Row Fb) "In Development" includes forecasted volumes from phase-in projects. This is consistent with labeling in the RPS Database (which labels phase-in projects as "In Development" under "Overall Project Status").**

**(12) (Row K) Row K now includes only expiring volumes from contracts as of April 30, 2015.**

*Stochastic Results in Rows Ga-Lb reflect a April 30, 2015 stochastic modeling vintage.

†Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans, Rulemaking ("R.") 13-12-010, filed December 19, 2013.

# APPENDIX C.2a

## Alternate Renewable Net Short Calculations – 33% RPS Target

August 4, 2015

# Appendix C.2a - Alternate Renewable Net Short Calculations – 33% RPS Target

## Stochastically-Optimized Net Short Calculation Using PG&E Bundled Retail Sales Forecast and Corrections to Formulas

| Variable | Calculation in Energy Division RNS Calculation Template | Revised Calculation Correcting Apparent Errors in Energy Division Template | Item | Deficit from RPS prior to Reporting Year | 2011 Actuals | 2012 Actuals | 2013 Actuals | 2011-2013 | 2014 Actuals | 2015 Forecast | 2016 Forecast | 2014-2016 | 2017 Forecast | 2018 Forecast | 2019 Forecast | 2020 Forecast | 2017-2020 | 2021 Forecast | 2022 Forecast | 2023 Forecast | 2024 Forecast | 2025 Forecast | 2026 Forecast | 2027 Forecast | 2028 Forecast | 2029 Forecast | 2030 Forecast | 2031 Forecast | 2032 Forecast | 2033 Forecast | 2034 Forecast | 2035 Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Forecast Year | | - | - | - | CP1 | - | - | - | CP2 | - | - | - | - | CP3 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | **Annual RPS Requirement** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| A | | | Bundled Retail Sales Forecast (Alternate)[1] | | 74,864 | 76,205 | 75,705 | 226,774 | 74,547 | 71,183 | 70,870 | 216,599 | [redacted] | 64,957 | 62,381 | 59,668 | [redacted] | 59,780 | 59,888 | 59,988 | 60,077 | 60,189 | 60,407 | 60,765 | 61,331 | 62,067 | 62,948 | 64,033 | 65,355 | 66,902 | 68,683 | 69,892 |
| B | | | RPS Procurement Quantity Requirement (%) | | 20.0% | 20.0% | 20.0% | 20.0% | 21.7% | 23.3% | 25.0% | 23.3% | 27.0% | 29.0% | 31.0% | 33.0% | 30.0% | 33.0% | 33.0% | 33.0% | 33.0% | 33.0% | 33.0% | 33.0% | 33.0% | 33.0% | 33.0% | 33.0% | 33.0% | 33.0% | 33.0% | 33.0% |
| C | A*B | | **Gross RPS Procurement Quantity Requirement (GWh)** | | 14,973 | 15,241 | 15,141 | 45,355 | 16,177 | 16,586 | 17,717 | 50,480 | [redacted] | 18,837 | 19,338 | 19,690 | [redacted] | 19,727 | 19,763 | 19,796 | 19,825 | 19,862 | 19,934 | 20,052 | 20,239 | 20,482 | 20,773 | 21,131 | 21,567 | 22,078 | 22,665 | 23,064 |
| D | | | Voluntary Margin of Over-procurement[2] | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| E | C+D | | **Net RPS Procurement Need (GWh)** | | 14,973 | 15,241 | 15,141 | 45,355 | 16,177 | 16,586 | 17,717 | 50,480 | [redacted] | 18,837 | 19,338 | 19,690 | [redacted] | 19,727 | 19,763 | 19,796 | 19,825 | 19,862 | 19,934 | 20,052 | 20,239 | 20,482 | 20,773 | 21,131 | 21,567 | 22,078 | 22,665 | 23,064 |
| | | | **RPS-Eligible Procurement** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Fa | | | Risk-Adjusted RECs from Online Generation[10] | | 14,699 | 14,513 | 17,212 | 46,424 | 20,206 | 22,092 | 21,967 | 64,265 | 21,693 | 19,728 | 19,038 | 18,198 | 78,656 | 17,772 | 15,361 | 15,028 | 14,760 | 14,648 | 14,084 | 13,842 | 13,791 | 13,235 | 13,170 | 12,807 | 12,280 | 11,060 | 10,060 | 9,276 |
| Faa | | | Forecast Failure Rate for Online Generation (%) | | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Fb | | | Risk-Adjusted RECs from RPS Facilities in Development[11] | | - | - | - | - | - | 363 | 943 | 1,306 | 1,981 | 2,113 | 2,518 | 2,702 | 9,314 | 2,737 | 2,725 | 2,713 | 2,707 | 2,690 | 2,679 | 2,667 | 2,661 | 2,644 | 2,633 | 2,605 | 2,230 | 2,182 | 1,888 | 1,498 |
| Fbb | | | Forecast Failure Rate for RPS Facilities in Development (%) | | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 5.5% | 3.2% | 2.9% | 1.5% | 1.4% | 1.2% | 1.1% | 1.3% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.2% | 1.3% | 1.4% | 0.6% |
| Fc | | | Pre-Approved Generic RECs | | - | - | - | - | - | - | 19 | 19 | 179 | 672 | 1,035 | 1,123 | 3,009 | 1,202 | 1,219 | 1,216 | 1,216 | 1,211 | 1,208 | 1,205 | 1,205 | 1,199 | 1,197 | 1,194 | 1,194 | 1,188 | 1,186 | 1,183 |
| Fd | | | Executed REC Sales | | - | - | (142) | (142) | (50) | - | - | (50) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| F | Fa + Fb +Fc - Fd | | Total RPS Eligible Procurement (GWh)[9] | | 14,699 | 14,513 | 17,069 | 46,281 | 20,156 | 22,455 | 22,930 | 65,541 | 23,853 | 22,512 | 22,590 | 22,023 | 90,979 | 21,711 | 19,305 | 18,957 | 18,683 | 18,549 | 17,971 | 17,714 | 17,657 | 17,078 | 17,000 | 16,605 | 15,704 | 14,430 | 13,134 | 11,956 |
| F0 | | | Category 0 RECs | | 14,637 | 13,035 | 14,149 | 41,821 | 16,886 | 18,251 | 18,053 | 53,190 | 17,756 | 15,822 | 15,137 | 14,297 | 63,013 | 13,889 | 11,501 | 11,207 | 10,982 | 10,898 | 10,345 | 10,112 | 10,065 | 9,538 | 9,493 | 9,178 | 9,082 | 8,457 | 7,823 | 7,376 |
| F1 | | | Category 1 RECs | | 62 | 1,478 | 2,921 | 4,461 | 3,270 | 4,204 | 4,877 | 12,351 | 6,097 | 6,690 | 7,454 | 7,726 | 27,966 | 7,822 | 7,805 | 7,750 | 7,701 | 7,651 | 7,626 | 7,602 | 7,592 | 7,540 | 7,507 | 7,427 | 6,622 | 5,973 | 5,311 | 4,580 |
| F2 | | | Category 2 RECs | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| F3 | | | Category 3 RECs | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | **Step 1 Result: Physical Net Short3** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Ga | F-E | | **Annual Gross RPS Position (GWh)** | | (274) | (728) | 1,928 | 926 | 3,979 | 5,869 | 5,212 | 15,061 | [redacted] | 3,675 | 3,252 | 2,332 | [redacted] | 1,984 | (458) | (839) | (1,142) | (1,314) | (1,964) | (2,339) | (2,582) | (3,404) | (3,773) | (4,526) | (5,863) | (7,647) | (9,532) | (11,108) |
| Gb | F/A | | **Annual Gross RPS Position (%)** | | 19.6% | 19.0% | 22.5% | 20.4% | 27.0% | 31.5% | 32.4% | 30.3% | [redacted] | 34.7% | 36.2% | 36.9% | [redacted] | 36.3% | 32.2% | 31.6% | 31.1% | 30.8% | 29.7% | 29.2% | 28.8% | 27.5% | 27.0% | 25.9% | 24.0% | 21.6% | 19.1% | 17.1% |

PG&E's Alternative RNS Table - Stochastic-Adjustment (2011-2035)

| Variable | Calculation in Energy Division RNS Calculation Template | Revised Calculation Correcting Apparent Errors in Energy Division Template | Item | Deficit from RPS prior to Reporting Year | 2011 Actuals | 2012 Actuals | 2013 Actuals | 2011-2013 Actuals | 2014 Actuals | 2015 Forecast | 2016 Forecast | 2014-2016 | 2017 Forecast | 2018 Forecast | 2019 Forecast | 2020 Forecast | 2017-2020 | 2021 Forecast | 2022 Forecast | 2023 Forecast | 2024 Forecast | 2025 Forecast | 2026 Forecast | 2027 Forecast | 2028 Forecast | 2029 Forecast | 2030 Forecast | 2031 Forecast | 2032 Forecast | 2033 Forecast | 2034 Forecast | 2035 Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | **Step 2 Result: Stochastically-Adjusted Net Short (Physical Net Short + Stochastic Risk-Adjustment)[4]** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Gd | | | **Stochastically-Adjusted Annual Gross RPS Position (GWh)** | | | | | 926 | | | | [redacted] | | | | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Ge | | | **Stochastically-Adjusted Annual Gross RPS Position (%)** | | | | | 20.4% | | | | [redacted] | | | | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | | **Application of Bank** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Ha | H - Hc (from previous year | J - Hc (from previous year) | Existing Banked RECs above the PQR (The Bank at Beg. Of Period)[5,6] | | | | | 0 | | | | 861 | | | | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Hb | | | RECs above the PQR added to Bank | | | | | 926 | | | | [redacted] | | | | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Hc | | | Non-bankable RECs above the PQR | | | | | 65 | | | | 119 | | | | | 83 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| H | Ha+Hb | | Gross Balance of RECs above the PQR | | | | | 926 | Optimization is Based on Compliance Period Only | | | [redacted] | Optimization is Based on Compliance Period Only | | | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Ia | | | Planned Application of RECs above the PQR towards RPS Compliance | | | | | - | | | | [redacted] | | | | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Ib | | | Planned Sales of RECs above the PQR[7] | | | | | - | | | | [redacted] | | | | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| J | H-Ia-Ib | | Net Balance of RECs above the PQR (The Bank at End of Period)[5] | | | | | 926 | | | | [redacted] | | | | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| J0 | | | Category 0 RECs | | | | | - | | | | [redacted] | | | | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| J1 | | | Category 1 RECs | | | | | 926 | | | | [redacted] | | | | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| J2 | | | Category 2 RECs | | | | | - | | | | [redacted] | | | | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| | | | **Expiring Contracts** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| K | | | RECs from Expiring RPS Contracts[12] | | N/A | N/A | N/A | N/A | - | 0.4 | 518 | 518 | 1,011 | 1,642 | 3,866 | 4,732 | 11,250 | 5,071 | 7,433 | 7,728 | 8,014 | 8,028 | 8,555 | 8,760 | 8,818 | 9,286 | 9,315 | 9,656 | 10,564 | 11,728 | 12,962 | 14,090 |
| | | | **Step 3 Result: Stochastically-Optimized Net Short (Stochastically-Adjusted Net Short + Application of Bank)[8]** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| La | Ga + Ia – Ib – Hc | Gd+Ia-Ib | **Annual Net RPS Position after Bank Optimization (GWh)** | | | | | 926 | Optimization is Based on Compliance Period Only | | | [redacted] | Optimization is Based on Compliance Period Only | | | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Lb | (F + Ia – Ib – Hc)/A | (Gd+Ia-Ib+E)/A | **Annual Net RPS Position after Bank Optimization (%)** | | | | | 20.4% | | | | [redacted] | | | | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

General Table Notes: Values are shown in GWhs. Fields in grey are protected as Confidential under CPUC Confidentiality Rules.

**(1) (Row A) PG&E uses its April 30, 2015 internal alternative load forecast for its procurement decisions.†**

**(2) (Row D) As a portion of the Bank will be used as VMOP, Row D will remain zero. See 2015 RPS Plan for a description of PG&E's VMOP.**

**(3) (Step 1 Result: Physical Net Short) Rows Ga and Gb represent PG&E's physical net short based on PG&E's internal bundled retail sales forecast, as opposed to the LTPP forecast provided in the RNS.**

**(4) (Step 2 Result: Stochastically-Adjusted Net Short (Physical Net Short+ Stochastic Risk-Adjustment) PG&E added rows Gd and Ge to the Alternative RNS in order to show the stochastically-adjusted physical net short, which incorporates the risks and uncertainties addressed in the stochastic model. For more details on PG&E's stochastically modeled risks, see the 2015 RPS Plan.**
This is prior to any application of the Bank.

**(5) (Rows Ha and J) As PG&E's Alternative RNS incorporates additional risk-adjustments to the results from the Physical Net Short, the Bank sizes indicated in Rows Ha and J appear smaller than they are in Rows Ha and J of the RNS, which shows the non-stochastically-adjusted Bank size.**

**(6) (Rows Ha) At the beginning of each compliance period Row Ha subtracts previous compliance non-bankable volumes from the previous compliance period net balance of RECs. For example, the 2021 forecast for Row Ha is equivalent to the Row J in CP3 minus Row Hc in CP3.**

**(7) (Row Ib) The purpose of the planned sales is to minimize the non-bankable volumes, but the actual sales could be a combination of bankable and non-bankable volumes.**

**(8) (Step 3 Result: Stochastically-Optimized Net Short (Stochastically-Adjusted Net Short + Application of Bank))**

(a) Rows La and Lb represent the optimized net short that results from taking Row Gd (Step 2 Result) and then applying Bank usage. Bank can be used for either (i) compliance purposes (row Ia) or (ii) sales (Row Ib).

(b) Row La in the Alternative RNS does not match Row La in the RNS, because the RNS does not include Row Gd (Stochastically-Adjusted Net Short).

(c) PG&E includes the non-bankable volumes in calculating rows La and Lb. Although these volumes can not be carried forward, per Decision 12-06-038, these volumes could be used towards meeting compliance in the current period. Therefore, the non-bankable volumes should be included in the Annual Net RPS Position after Bank Optimization.

**(9) (Row F) Row F has subtracted 134 GWh of RECs associated with 2011 generation from the Hay Canyon Wind Facility and the Nine Canyon Wind Phase 3. These RECs are not being used for RPS compliance because they were not retired within the RPS statute's 36-month REC retirement deadline.**

**(10) (Row Fa) "Online Generation" includes forecasted volumes from replacement contracts (i.e. ReMAT contracts replacing QF contracts) for facilities that are already online.**

**(11) (Row Fb) "In Development" includes forecasted volumes from phase-in projects. This is consistent with labeling in the RPS Database (which labels phase-in projects as "In Development" under "Overall Project Status").**

**(12) (Row K) Row K now includes only expiring volumes from contracts as of April 30, 2015.**

*Stochastic Results in Rows Gd-Lb reflect a April 30, 2015 stochastic modeling vintage.

†Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans, Rulemaking ("R.") 13-12-010, filed December 19, 2013.

# APPENDIX C.2b

# Alternate Renewable Net Short Calculations – 40% RPS Scenario

August 4, 2015

# Appendix C.2b - Alternate Renewable Net Short Calculations - 40% RPS Scenario

## Stochastically-Optimized Net Short Calculation Using PG&E Bundled Retail Sales Forecast and Corrections to Formulas

| Variable | Calculation in Energy Division RNS Calculation Template | Revised Calculation Correcting Apparent Errors in Energy Division Template | Item | Deficit from RPS prior to Reporting Year | 2011 Actuals | 2012 Actuals | 2013 Actuals | **2011-2013** | 2014 Actuals | 2015 Forecast | 2016 Forecast | **2014-2016** | 2017 Forecast | 2018 Forecast | 2019 Forecast | 2020 Forecast | **2017-2020** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Forecast Year | | - | - | - | CP1 | - | - | - | CP2 | - | - | - | - | CP3 |
| | | | **Annual RPS Requirement** | | | | | | | | | | | | | | |
| A | | | Bundled Retail Sales Forecast (Alternate)[1] | | 74,864 | 76,205 | 75,705 | 226,774 | 74,547 | 71,183 | 70,870 | 216,599 | [redacted] | 64,957 | 62,381 | 59,668 | [redacted] |
| B | | | RPS Procurement Quantity Requirement (%) | | 20.0% | 20.0% | 20.0% | 20.0% | 21.7% | 23.3% | 25.0% | 23.3% | 27.0% | 29.0% | 31.0% | 33.0% | 30.0% |
| C | A*B | | **Gross RPS Procurement Quantity Requirement (GWh)** | | 14,973 | 15,241 | 15,141 | 45,355 | 16,177 | 16,586 | 17,717 | 50,480 | [redacted] | 18,837 | 19,338 | 19,690 | [redacted] |
| D | | | Voluntary Margin of Over-procurement[2] | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| E | C+D | | **Net RPS Procurement Need (GWh)** | | 14,973 | 15,241 | 15,141 | 45,355 | 16,177 | 16,586 | 17,717 | 50,480 | [redacted] | 18,837 | 19,338 | 19,690 | [redacted] |
| | | | **RPS-Eligible Procurement** | | | | | | | | | | | | | | |
| Fa | | | Risk-Adjusted RECs from Online Generation[10] | | 14,699 | 14,513 | 17,212 | 46,424 | 20,206 | 22,092 | 21,967 | 64,265 | 21,693 | 19,728 | 19,038 | 18,198 | 78,656 |
| Faa | | | Forecast Failure Rate for Online Generation (%) | | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Fb | | | Risk-Adjusted RECs from RPS Facilities in Development[11] | | - | - | - | - | - | 363 | 943 | 1,306 | 1,981 | 2,113 | 2,518 | 2,702 | 9,314 |
| Fbb | | | Forecast Failure Rate for RPS Facilities in Development (%) | | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 5.5% | 3.2% | 2.9% | 1.5% | 1.4% | 1.2% | 1.1% | 1.3% |
| Fc | | | Pre-Approved Generic RECs | | - | - | - | - | - | - | 19 | 19 | 179 | 672 | 1,035 | 1,123 | 3,009 |
| Fd | | | Executed REC Sales | | - | - | (142) | (142) | (50) | - | - | (50) | - | - | - | - | - |
| F | Fa + Fb +Fc - Fd | | Total RPS Eligible Procurement (GWh)[9] | | 14,699 | 14,513 | 17,069 | 46,281 | 20,156 | 22,455 | 22,930 | 65,541 | 23,853 | 22,512 | 22,590 | 22,023 | 90,979 |
| F0 | | | Category 0 RECs | | 14,637 | 13,035 | 14,149 | 41,821 | 16,886 | 18,251 | 18,053 | 53,190 | 17,756 | 15,822 | 15,137 | 14,297 | 63,013 |
| F1 | | | Category 1 RECs | | 62 | 1,478 | 2,921 | 4,461 | 3,270 | 4,204 | 4,877 | 12,351 | 6,097 | 6,690 | 7,454 | 7,726 | 27,966 |
| F2 | | | Category 2 RECs | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| F3 | | | Category 3 RECs | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | **Step 1 Result: Physical Net Short3** | | | | | | | | | | | | | | |
| Ga | F-E | | **Annual Gross RPS Position (GWh)** | | (274) | (728) | 1,928 | 926 | 3,979 | 5,869 | 5,212 | 15,061 | [redacted] | 3,675 | 3,252 | 2,332 | [redacted] |
| Gb | F/A | | **Annual Gross RPS Position (%)** | | 19.6% | 19.0% | 22.5% | 20.4% | 27.0% | 31.5% | 32.4% | 30.3% | [redacted] | 34.7% | 36.2% | 36.9% | [redacted] |

| Variable | 2021 Forecast | 2022 Forecast | 2023 Forecast | 2024 Forecast | 2025 Forecast | 2026 Forecast | 2027 Forecast | 2028 Forecast | 2029 Forecast | 2030 Forecast | 2031 Forecast | 2032 Forecast | 2033 Forecast | 2034 Forecast | 2035 Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | |
| A | 59,780 | 59,888 | 59,988 | 60,077 | 60,189 | 60,407 | 60,765 | 61,331 | 62,067 | 62,948 | 64,033 | 65,355 | 66,902 | 68,683 | 69,892 |
| B | 33.0% | 37.0% | 37.0% | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% |
| C | 19,727 | 22,159 | 22,195 | 24,031 | 24,075 | 24,163 | 24,306 | 24,532 | 24,827 | 25,179 | 25,613 | 26,142 | 26,761 | 27,473 | 27,957 |
| D | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| E | 19,727 | 22,159 | 22,195 | 24,031 | 24,075 | 24,163 | 24,306 | 24,532 | 24,827 | 25,179 | 25,613 | 26,142 | 26,761 | 27,473 | 27,957 |
| | | | | | | | | | | | | | | | |
| Fa | 17,772 | 15,361 | 15,028 | 14,760 | 14,648 | 14,084 | 13,842 | 13,791 | 13,235 | 13,170 | 12,807 | 12,280 | 11,060 | 10,060 | 9,276 |
| Faa | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Fb | 2,737 | 2,725 | 2,713 | 2,707 | 2,690 | 2,679 | 2,667 | 2,661 | 2,644 | 2,633 | 2,605 | 2,230 | 2,182 | 1,888 | 1,498 |
| Fbb | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.1% | 1.2% | 1.3% | 1.4% | 0.6% |
| Fc | 1,202 | 1,219 | 1,216 | 1,216 | 1,211 | 1,208 | 1,205 | 1,205 | 1,199 | 1,197 | 1,194 | 1,194 | 1,188 | 1,186 | 1,183 |
| Fd | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| F | 21,711 | 19,305 | 18,957 | 18,683 | 18,549 | 17,971 | 17,714 | 17,657 | 17,078 | 17,000 | 16,605 | 15,704 | 14,430 | 13,134 | 11,956 |
| F0 | 13,889 | 11,501 | 11,207 | 10,982 | 10,898 | 10,345 | 10,112 | 10,065 | 9,538 | 9,493 | 9,178 | 9,082 | 8,457 | 7,823 | 7,376 |
| F1 | 7,822 | 7,805 | 7,750 | 7,701 | 7,651 | 7,626 | 7,602 | 7,592 | 7,540 | 7,507 | 7,427 | 6,622 | 5,973 | 5,311 | 4,580 |
| F2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| F3 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | |
| Ga | 1,984 | (2,853) | (3,238) | (5,348) | (5,527) | (6,192) | (6,592) | (6,875) | (7,748) | (8,179) | (9,008) | (10,438) | (12,331) | (14,340) | (16,000) |
| Gb | 36.3% | 32.2% | 31.6% | 31.1% | 30.8% | 29.7% | 29.2% | 28.8% | 27.5% | 27.0% | 25.9% | 24.0% | 21.6% | 19.1% | 17.1% |

PG&E's Alternative RNS Table - Stochastic-Adjustment (2011-2035)

| Variable | Calculation in Energy Division RNS Calculation Template | Revised Calculation Correcting Apparent Errors in Energy Division Template | Item | Deficit from RPS prior to Reporting Year | 2011 Actuals | 2012 Actuals | 2013 Actuals | 2011-2013 Actuals | 2014 Actuals | 2015 Forecast | 2016 Forecast | **2014-2016** | 2017 Forecast | 2018 Forecast | 2019 Forecast | 2020 Forecast | **2017-2020** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | **Step 2 Result: Stochastically-Adjusted Net Short (Physical Net Short + Stochastic Risk-Adjustment)[4]** | | | | | | | | | | | | | | |
| Gd | | | **Stochastically-Adjusted Annual Gross RPS Position (GWh)** | | | | | 926 | | | | [redacted] | | | | | [redacted] |
| Ge | | | **Stochastically-Adjusted Annual Gross RPS Position (%)** | | | | | 20.4% | | | | [redacted] | | | | | [redacted] |
| | | | **Application of Bank** | | | | | | | | | | | | | | |
| Ha | H - Hc (from previous year) | J - Hc (from previous year) | Existing Banked RECs above the PQR (The Bank at Beg. Of Period)[5,6] | | | | | - | | | | 861 | | | | | [redacted] |
| Hb | | | RECs above the PQR added to Bank | | | | | 926 | | | | [redacted] | | | | | [redacted] |
| Hc | | | Non-bankable RECs above the PQR | | | | | 65 | | | | 119 | | | | | 83 |
| H | Ha+Hb | | Gross Balance of RECs above the PQR | | | | | 926 | Optimization is Based on Compliance Period Only | | | [redacted] | Optimization is Based on Compliance Period Only | | | | [redacted] |
| Ia | | | Planned Application of RECs above the PQR towards RPS Compliance | | | | | - | | | | [redacted] | | | | | [redacted] |
| Ib | | | Planned Sales of RECs above the PQR[7] | | | | | - | | | | [redacted] | | | | | [redacted] |
| J | H-Ia-Ib | | Net Balance of RECs above the PQR (The Bank at End of Period)[5] | | | | | 926 | | | | [redacted] | | | | | [redacted] |
| J0 | | | Category 0 RECs | | | | | - | | | | [redacted] | | | | | [redacted] |
| J1 | | | Category 1 RECs | | | | | 926 | | | | [redacted] | | | | | [redacted] |
| J2 | | | Category 2 RECs | | | | | - | | | | [redacted] | | | | | [redacted] |
| | | | **Expiring Contracts** | | | | | | | | | | | | | | |
| K | | | RECs from Expiring RPS Contracts[12] | | N/A | N/A | N/A | N/A | - | 0.4 | 518 | 518 | 1,011 | 1,642 | 3,866 | 4,732 | 11,250 |
| | | | **Step 3 Result: Stochastically-Optimized Net Short (Stochastically-Adjusted Net Short + Application of Bank)[8]** | | | | | | | | | | | | | | |
| La | Ga + Ia – Ib – Hc | Gd+Ia-Ib | **Annual Net RPS Position after Bank Optimization (GWh)** | | | | | 926 | Optimization is Based on Compliance Period Only | | | [redacted] | Optimization is Based on Compliance Period Only | | | | [redacted] |
| Lb | (F + Ia – Ib – Hc)/A | (Gd+Ia-Ib+E)/A | **Annual Net RPS Position after Bank Optimization (%)** | | | | | 20.4% | | | | [redacted] | | | | | [redacted] |

| Variable | 2021 Forecast | 2022 Forecast | 2023 Forecast | 2024 Forecast | 2025 Forecast | 2026 Forecast | 2027 Forecast | 2028 Forecast | 2029 Forecast | 2030 Forecast | 2031 Forecast | 2032 Forecast | 2033 Forecast | 2034 Forecast | 2035 Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Gd–Hb | [redacted] | | | | | | | | | | | | | | |
| Hc | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| H–J2 | [redacted] | | | | | | | | | | | | | | |
| K | 5,071 | 7,433 | 7,728 | 8,014 | 8,028 | 8,555 | 8,760 | 8,818 | 9,286 | 9,315 | 9,656 | 10,564 | 11,728 | 12,962 | 14,090 |
| La–Lb | [redacted] | | | | | | | | | | | | | | |

General Table Notes: Values are shown in GWhs. Fields in grey are protected as Confidential under CPUC Confidentiality Rules.

**(1) (Row A) PG&E uses its April 30, 2015 internal alternative load forecast for its procurement decisions.†**

**(2) (Row D) As a portion of the Bank will be used as VMOP, Row D will remain zero. See 2015 RPS Plan for a description of PG&E's VMOP.**

**(3) (Step 1 Result: Physical Net Short) Rows Ga and Gb represent PG&E's physical net short based on PG&E's internal bundled retail sales forecast, as opposed to the LTPP forecast provided in the RNS.**

**(4) (Step 2 Result: Stochastically-Adjusted Net Short (Physical Net Short+ Stochastic Risk-Adjustment) PG&E added rows Gd and Ge to the Alternative RNS in order to show the stochastically-adjusted physical net short, which incorporates the risks and uncertainties addressed in the stochastic model. For more details on PG&E's stochastically modeled risks, see the 2015 RPS Plan.**
This is prior to any application of the Bank.

**(5) (Rows Ha and J) As PG&E's Alternative RNS incorporates additional risk-adjustments to the results from the Physical Net Short, the Bank sizes indicated in Rows Ha and J appear smaller than they are in Rows Ha and J of the RNS, which shows the non-stochastically-adjusted Bank size.**

**(6) (Rows Ha) At the beginning of each compliance period Row Ha subtracts previous compliance non-bankable volumes from the previous compliance period net balance of RECs. For example, the 2021 forecast for Row Ha is equivalent to the Row J in CP3 minus Row Hc in CP3.**

**(7) (Row Ib) The purpose of the planned sales is to minimize the non-bankable volumes, but the actual sales could be a combination of bankable and non-bankable volumes.**

**(8) (Step 3 Result: Stochastically-Optimized Net Short (Stochastically-Adjusted Net Short + Application of Bank))**

(a) Rows La and Lb represent the optimized net short that results from taking Row Gd (Step 2 Result) and then applying Bank usage. Bank can be used for either (i) compliance purposes (row Ia) or (ii) sales (Row Ib).

(b) Row La in the Alternative RNS does not match Row La in the RNS, because the RNS does not include Row Gd (Stochastically-Adjusted Net Short).

(c) PG&E includes the non-bankable volumes in calculating rows La and Lb. Although these volumes can not be carried forward, per Decision 12-06-038, these volumes could be used towards meeting compliance in the current period. Therefore, the non-bankable volumes should be included in the Annual Net RPS Position after Bank Optimization.

**(9) (Row F) Row F has subtracted 134 GWh of RECs associated with 2011 generation from the Hay Canyon Wind Facility and the Nine Canyon Wind Phase 3. These RECs are not being used for RPS compliance because they were not retired within the RPS statute's 36-month REC retirement deadline.**

**(10) (Row Fa) "Online Generation" includes forecasted volumes from replacement contracts (i.e. ReMAT contracts replacing QF contracts) for facilities that are already online.**

**(11) (Row Fb) "In Development" includes forecasted volumes from phase-in projects. This is consistent with labeling in the RPS Database (which labels phase-in projects as "In Development" under "Overall Project Status").**

**(12) (Row K) Row K now includes only expiring volumes from contracts as of April 30, 2015.**

*Stochastic Results in Rows Gd-Lb reflect a April 30, 2015 stochastic modeling vintage.

†Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans, Rulemaking ("R.") 13-12-010, filed December 19, 2013.

# APPENDIX D

# Procurement Information Related to Cost Quantification

August 4, 2015

# Appendix D – Procurement Information Related to Cost Quantification

| Assumptions | |
|---|---|
| **Table 1 (Actual Costs, $) Items** | **Actual** |
| Rows 2 -- 8, 11 (2003-2014)[1, 2, 3, 4, 5, 6] | Settled contract costs with all RPS-eligible contracts in PG&E's portfolio for 2003-2014 |
| Row 9 | For 2003-2011, capital costs are based on the net book value of PG&E's RPS-eligible units as of December 2011 multiplied by an assumed fixed charge rate equal to 14%. For 2012 through 2014, capital costs are based on the net book value of PG&E's RPS-eligible units as of December of that respective year multiplied by a fixed charge rate of 14%. PG&E's actual operation and maintenance (O&M) costs for each year (2003-2014) were added to each year's capital costs to calculate total costs. |
| Row 10 | LCOE for each project multiplied by the project's historical generation |
| Row 13 | PG&E actual bundled retail sales |
| Row 14 | Total Cost / Bundled Retail Sales (Row 12 / Row 13) |
| **Table 2 (Forecast Costs, $) Items** | **Forecast** |
| Rows 2 -- 8, 11, 16 -- 22, 25 | PG&E's future expenditures on all RPS-eligible procurement and generation either (1) approved to date or (2) executed prior to April 2015 but pending CPUC approval. 2015 data represent a September 2014 vintage and 2016-2030 data represent a April 2015 vintage to be consistent with the 2015 Integrated Energy Policy Report (IEPR). |
| Rows 9 and 23 | For 2015-2030, annualized capital costs based on the net book value of PG&E's RPS-eligible units as of December 2014 were added to operation and maintenance (O&M) costs, which were calculated as 2014 O&M costs escalated at 5% annually for each year. |
| Row 10 and 24 | LCOE for each project multiplied by the project's forecasted generation |
| Rows 13 and 27 | PG&E bundled retail sales forecast |
| Rows 14 and 28 | Total Cost / Bundled Sales |
| Row 29 | Row 14 + Row 28 |
| **Table 3 (Actual Generation, MWh) Items** | **Actual** |
| Rows 2 -- 11[1, 3, 4, 5, 6] | Generation (MWh) associated with payments for RPS-eligible deliveries |
| **Table 4 (Forecast Generation, MWh) Items** | **Forecast** |
| Rows 2 -- 11 and 16-25 | Forecasted RPS-eligible generation (MWh) either (1) approved to date or (2) executed prior to April 2015 but pending Commission approval -- assumes no contract failure, and all contractual volumes are forecast at 100% of expected volumes. 2015 data represent a September 2014 vintage and 2016-2030 data represent a April 2015 vintage to be consistent with the 2015 Integrated Energy Policy Report (IEPR). |

[1] 2014 Generation and Costs were updated to reflect best available data as of March 2015.

[2] Row 5 includes the aggregate costs (specifically debt service and operation and maintenance) of PG&E's contract with Solano Irrigation District (SID) who supplies power from multiple hydro units, 100% of which are RPS-eligible. SID's costs include the costs to operate and maintain the hydro units and project facilities (dams and waterways). Yuba County Water Agency (YCWA) does not operate any RPS-eligible hydro units, therefore YCWA cost data is not relevant and thereby not included.

[3] RPS-eligible generation reported in 2014 is the best available settlements data as of March 2015 and therefore contains actual data as settlements data for the prior year can continue to be adjusted after January of the current year. As UOG Hydro and UOG Solar estimates are calculated separately, 2013 data for these two technology types is the best available as of April 2014.

[4] Energy volumes reported in Rows 2-8 represent the generation (MWh) associated with payments for RPS-eligible deliveries, which can differ from the energy volumes PG&E claims for the purposes of complying with California's RPS Program. For example, some RPS contracts require PG&E to only pay for RPS-eligible deliveries based on scheduled energy, but entitle PG&E to all green attributes generated and metered by the facility. Since compliance with California's RPS Program is based on metered generation, scheduled/paid volumes may not always match the metered/compliance volumes.

[5] Cost for executed sales are a combination of geothermal and small hydro volumes. As the costs are a combined payment not divided by technology type, PG&E allocated technology specific costs based on the technology specific generation (MWh) of the sale contract.

[6] Some immaterial changes have been made to cost and generation data from 2005, 2011, and 2013 as compared to the 2014 RPS Plan. 2005 changes are due to a 2006 RPS wind contract being accidently included in 2005. 2011 data changes are due to a mislabeling of a biogas contract as biomass. 2013 changes represent updated settlements data.

**Note:** As with any forecasting exercise, projections are predicated on a number of necessarily speculative assumptions and will be impacted by future events, including regulatory decisions resulting in different costs or rate treatments. Thus, PG&E cannot guarantee that the information contained in this summary will reflect actual future rates, revenue requirements, or sales.

# Appendix D – Procurement Information Related to Cost Quantification

## Joint IOU Cost Quantification Table 1
## (Actual Costs, $ Thousands)

| | | **Actual RPS-Eligible Procurement and Generation Costs** | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Technology Type** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** |
| 2 | Biogas | $25,762 | $23,856 | $25,623 | $22,823 | $24,126 | $23,468 | $27,306 | $20,216 | $16,776 | $5,333 | $5,063 | $11,087 |
| 3 | Biomass | $215,078 | $217,923 | $217,279 | $222,125 | $238,524 | $259,957 | $262,086 | $263,994 | $245,622 | $302,711 | $299,205 | $317,301 |
| 4 | Geothermal | $110,572 | $111,778 | $108,720 | $118,523 | $199,143 | $282,227 | $200,357 | $260,053 | $223,575 | $209,854 | $284,334 | $324,050 |
| 5 | Small Hydro | $60,984 | $57,470 | $80,340 | $97,340 | $63,161 | $72,488 | $52,053 | $63,296 | $84,864 | $54,140 | $57,213 | $45,522 |
| 6 | Solar PV | $0 | $0 | $0 | $0 | $0 | $0 | $2,554 | $10,180 | $33,370 | $176,372 | $504,860 | $803,806 |
| 7 | Solar Thermal | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $1,698 | $173,856 |
| 8 | Wind | $65,244 | $74,912 | $56,891 | $67,116 | $98,203 | $102,516 | $199,475 | $224,089 | $340,517 | $379,416 | $424,764 | $437,159 |
| 9 | UOG Small Hydro | $44,936 | $45,059 | $46,526 | $47,556 | $47,933 | $49,009 | $47,567 | $49,684 | $52,099 | $51,572 | $64,691 | $66,066 |
| 10 | UOG Solar | $0 | $0 | $0 | $0 | $227 | $452 | $473 | $1,498 | $5,620 | $27,093 | $43,882 | $52,426 |
| 11 | Unbundled RECs[1] | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | [redacted] | | | |
| 12 | **Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 11] | **$522,576** | **$530,998** | **$535,380** | **$575,483** | **$671,317** | **$790,116** | **$791,870** | **$893,010** | | | | |
| 13 | Bundled Retail Sales [Thousands of kWh] | 71,099,363 | 72,113,608 | 72,371,532 | 76,356,279 | 79,078,319 | 81,523,859 | 79,624,479 | 77,485,129 | 74,863,941 | 76,205,120 | 75,705,039 | 74,546,865 |
| 14 | **Incremental Rate Impact[2]** | **0.73 ¢/kWh** | **0.74 ¢/kWh** | **0.74 ¢/kWh** | **0.75 ¢/kWh** | **0.85 ¢/kWh** | **0.97 ¢/kWh** | **0.99 ¢/kWh** | **1.15 ¢/kWh** | [redacted] | | | |

[1] The cost of Unbundled RECs are separated from their technology type and only reported in the Unbundled RECs row. For example, the cost of an Unbundled REC procured from a wind facility is only reported in the Unbundled RECs row.

[2] Incremental Rate Impact is equal to Row 12 divided by Row 13. While the item is labeled "Incremental Rate Impact," the value should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable "premium." In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

# Appendix D – Procurement Information Related to Cost Quantification

## Joint IOU Cost Quantification Table 2
## (Forecast Costs, $ Thousands)

| | | Forecasted Future Expenditures on RPS-Eligible Procurement and Generation Costs | | | | | |
|---|---|---|---|---|---|---|---|
| 1 | **Executed But Not CPUC-Approved RPS-Eligible Contracts** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| 2 | Biogas | $0 | $0 | $0 | $0 | $0 | $0 |
| 3 | Biomass | $0 | $0 | $0 | $0 | $0 | $0 |
| 4 | Geothermal | $0 | $0 | $0 | $0 | $0 | $0 |
| 5 | Small Hydro | $0 | $0 | $0 | $0 | $0 | $0 |
| 6 | Solar PV | $0 | $0 | $0 | $0 | $0 | $0 |
| 7 | Solar Thermal | $0 | $0 | $0 | $0 | $0 | $0 |
| 8 | Wind | $0 | $0 | $0 | $0 | $0 | $0 |
| 9 | UOG Small Hydro | $0 | $0 | $0 | $0 | $0 | $0 |
| 10 | UOG Solar | $0 | $0 | $0 | $0 | $0 | $0 |
| 11 | Unbundled RECs[1] | $0 | $0 | $0 | $0 | $0 | $0 |
| 12 | **Total Executed But Not CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 11] | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** |
| 13 | Bundled Retail Sales [Thousands of kWh] | 71,182,544 | 70,869,576 | [redacted] | 64,956,724 | 62,381,387 | 59,668,061 |
| 14 | **Incremental Rate Impact[2]** | **0.000 ¢/kWh** | **0.000 ¢/kWh** | **0.000 ¢/kWh** | **0.000 ¢/kWh** | **0.000 ¢/kWh** | **0.000 ¢/kWh** |
| 15 | **CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| 16 | Biogas | $22,780 | $23,189 | $29,915 | $29,994 | $29,986 | $30,143 |
| 17 | Biomass | $311,380 | $270,577 | $241,040 | $219,990 | $193,377 | $136,275 |
| 18 | Geothermal | $329,015 | $311,371 | $314,874 | $193,171 | $194,611 | $196,294 |
| 19 | Small Hydro | $76,539 | $71,939 | $62,257 | $55,181 | $52,386 | $43,648 |
| 20 | Solar PV | $887,525 | $914,533 | $978,108 | $983,227 | $1,008,977 | $1,028,248 |
| 21 | Solar Thermal | $329,978 | $329,961 | $329,165 | $328,838 | $328,759 | $330,446 |
| 22 | Wind | $449,274 | $432,664 | $427,910 | $425,276 | $408,949 | $409,845 |
| 23 | UOG Small Hydro | $67,407 | $68,815 | $70,294 | $71,847 | $73,477 | $75,189 |
| 24 | UOG Solar | $51,674 | $51,406 | $51,139 | $50,874 | $50,610 | $50,347 |
| 25 | Unbundled RECs[1] | [redacted] | $0 | $0 | $0 | $0 | $0 |
| 26 | **Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 16 through 25] | [redacted] | **$2,474,455** | **$2,504,704** | **$2,358,397** | **$2,341,133** | **$2,300,435** |
| 27 | Bundled Retail Sales [Thousands of kWh] | 71,182,544 | 70,869,576 | [redacted] | 64,956,724 | 62,381,387 | 59,668,061 |
| 28 | **Incremental Rate Impact[2]** | [redacted] | **3.49 ¢/kWh** | [redacted] | **3.63 ¢/kWh** | **3.75 ¢/kWh** | **3.86 ¢/kWh** |
| 29 | **Total Incremental Rate Impact** [Row 14 + 28; Rounding can cause Row 29 to differ from Row 14 + 28] | [redacted] | **3.49 ¢/kWh** | [redacted] | **3.63 ¢/kWh** | **3.75 ¢/kWh** | **3.86 ¢/kWh** |

[1] See footnote 1 from Table 1.

[2] Incremental Rate Impact is equal to a Total Cost (either Row 12 or 26) divided by Bundled Retail Sales (either Row 13 or 27). While the item is labeled "Incremental Rate Impact," the value should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable "premium." In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

## Appendix D – Procurement Information Related to Cost Quantification

### Joint IOU Cost Quantification Table 2 (continued)
### (Forecast Costs, $ Thousands)

| | | Forecasted Future Expenditures on RPS-Eligible Procurement and Generation Costs | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Executed But Not CPUC-Approved RPS-Eligible Contracts** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| 2 | Biogas | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 3 | Biomass | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4 | Geothermal | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 5 | Small Hydro | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 6 | Solar PV | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 7 | Solar Thermal | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 8 | Wind | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9 | UOG Small Hydro | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 10 | UOG Solar | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 11 | Unbundled RECs[1] | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12 | **Total Executed But Not CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 11] | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** |
| 13 | Bundled Retail Sales [Thousands of kWh] | 59,779,916 | 59,888,425 | 59,987,654 | 60,077,196 | 60,188,640 | 60,407,333 | 60,765,057 | 61,330,567 | 62,066,738 | 62,947,785 |
| 14 | **Incremental Rate Impact**[2] | **0.00 ¢/kWh** | **0.00 ¢/kWh** | **0.00 ¢/kWh** | **0.00 ¢/kWh** | **0.00 ¢/kWh** | **0.00 ¢/kWh** | **0.00 ¢/kWh** | **0.00 ¢/kWh** | **0.00 ¢/kWh** | **0.00 ¢/kWh** |
| 15 | **CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| 16 | Biogas | $30,098 | $30,190 | $30,175 | $29,839 | $29,408 | $29,107 | $29,167 | $29,288 | $27,193 | $26,884 |
| 17 | Biomass | $127,551 | $128,345 | $129,109 | $130,224 | $130,865 | $131,575 | $99,946 | $95,123 | $95,038 | $95,228 |
| 18 | Geothermal | $196,819 | $13,563 | $13,470 | $13,423 | $13,314 | $13,256 | $13,174 | $13,121 | $12,997 | $12,921 |
| 19 | Small Hydro | $35,937 | $29,846 | $29,039 | $29,202 | $28,968 | $29,258 | $29,666 | $29,695 | $24,716 | $24,619 |
| 20 | Solar PV | $1,024,724 | $1,021,926 | $1,017,959 | $1,016,112 | $1,013,141 | $1,014,002 | $1,010,252 | $1,008,497 | $1,000,500 | $996,987 |
| 21 | Solar Thermal | $329,547 | $329,514 | $329,165 | $329,232 | $329,063 | $329,978 | $329,547 | $329,639 | $328,838 | $328,759 |
| 22 | Wind | $403,463 | $397,706 | $378,153 | $353,862 | $351,789 | $287,146 | $287,350 | $288,065 | $251,628 | $250,960 |
| 23 | UOG Small Hydro | $76,987 | $78,874 | $80,856 | $82,937 | $85,122 | $87,416 | $89,825 | $92,354 | $95,010 | $97,798 |
| 24 | UOG Solar | $50,086 | $49,826 | $49,568 | $49,311 | $49,055 | $48,801 | $48,548 | $48,296 | $48,045 | $47,796 |
| 25 | Unbundled RECs[1] | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 26 | **Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 16 through 25] | **$2,275,213** | **$2,079,790** | **$2,057,495** | **$2,034,141** | **$2,030,724** | **$1,970,537** | **$1,937,475** | **$1,934,078** | **$1,883,965** | **$1,881,953** |
| 27 | Bundled Retail Sales [Thousands of kWh] | 59,779,916 | 59,888,425 | 59,987,654 | 60,077,196 | 60,188,640 | 60,407,333 | 60,765,057 | 61,330,567 | 62,066,738 | 62,947,785 |
| 28 | **Incremental Rate Impact**[2] | **3.81 ¢/kWh** | **3.47 ¢/kWh** | **3.43 ¢/kWh** | **3.39 ¢/kWh** | **3.37 ¢/kWh** | **3.26 ¢/kWh** | **3.19 ¢/kWh** | **3.15 ¢/kWh** | **3.04 ¢/kWh** | **2.99 ¢/kWh** |
| 29 | **Total Incremental Rate Impact** [Row 14 + 28; Rounding can cause Row 29 to differ from Row 14 + 28] | **3.81 ¢/kWh** | **3.47 ¢/kWh** | **3.43 ¢/kWh** | **3.39 ¢/kWh** | **3.37 ¢/kWh** | **3.26 ¢/kWh** | **3.19 ¢/kWh** | **3.15 ¢/kWh** | **3.04 ¢/kWh** | **2.99 ¢/kWh** |

[1] See footnote 1 from Table 1.

[2] Incremental Rate Impact is equal to a Total Cost (either Row 12 or 26) divided by Bundled Retail Sales (either Row 13 or 27). While the item is labeled “Incremental Rate Impact,” the value should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable “premium.” In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

## Appendix D – Procurement Information Related to Cost Quantification

### Joint IOU Cost Quantification Table 3
### (Actual Generation, MWh)

| | | Actual RPS-Eligible Procurement and Generation (MWh) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Technology Type** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** |
| 2 | Biogas | 364,745 | 333,897 | 366,514 | 300,943 | 293,147 | 280,795 | 342,362 | 306,909 | 284,129 | 112,153 | 85,706 | 112,161 |
| 3 | Biomass | 2,839,795 | 2,961,633 | 2,858,643 | 2,770,398 | 2,751,813 | 2,813,819 | 3,122,048 | 2,990,615 | 3,043,656 | 3,158,131 | 3,055,370 | 3,226,904 |
| 4 | Geothermal | 1,674,702 | 1,753,043 | 1,687,360 | 1,790,870 | 2,701,970 | 3,350,232 | 3,411,798 | 3,766,700 | 3,780,954 | 3,807,728 | 3,687,236 | 3,870,952 |
| 5 | Small Hydro | 1,269,233 | 1,096,183 | 1,457,339 | 1,760,707 | 927,879 | 945,921 | 937,626 | 1,092,707 | 1,457,714 | 863,606 | 652,953 | 400,300 |
| 6 | Solar PV | 6 | 4 | 4 | 3 | 1 | 1 | 21,706 | 58,593 | 179,171 | 1,006,145 | 3,358,366 | 5,266,030 |
| 7 | Solar Thermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 20,581 | 878,905 |
| 8 | Wind | 940,239 | 1,078,579 | 874,204 | 1,019,451 | 1,374,337 | 1,439,796 | 2,557,988 | 2,981,660 | 4,395,377 | 4,515,452 | 4,924,052 | 5,358,546 |
| 9 | UOG Small Hydro | 1,382,934 | 1,267,084 | 1,403,130 | 1,437,196 | 984,607 | 993,266 | 1,103,017 | 1,157,077 | 1,254,638 | 948,734 | 1,394,189 | 1,292,552 |
| 10 | UOG Solar | 0 | 0 | 0 | 0 | 225 | 445 | 504 | 4,642 | 26,790 | 165,656 | 279,500 | 336,905 |
| 11 | Unbundled RECs[2] | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 102,888 | 108,874 | 101,256 | 100,581 |
| 12 | **Total CPUC-Approved RPS-Eligible Procurement and Generation** [Sum of Rows 2 through 11] | 8,471,654 | 8,490,423 | 8,647,195 | 9,079,568 | 9,033,979 | 9,824,276 | 11,497,048 | 12,358,903 | 14,525,317 | 14,686,479 | 17,559,209 | 20,843,836 |

[1] Energy Volumes reported for 2014 in Rows 2 – 11 are the best available settlements data as of March 2015.

[2] Row 11 only includes Unbundled RECs with CPUC approval.

## Joint IOU Cost Quantification Table 4
## (Forecast Generation, MWh)

| | | Forecasted Future RPS-Deliveries 2015-2020 (MWh) | | | | | |
|---|---|---|---|---|---|---|---|
| 1 | **Executed But Not CPUC-Approved RPS-Eligible Contracts** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| 2 | Biogas | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | Biomass | 0 | 0 | 0 | 0 | 0 | 0 |
| 4 | Geothermal | 0 | 0 | 0 | 0 | 0 | 0 |
| 5 | Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 |
| 6 | Solar PV | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | Solar Thermal | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Wind | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | UOG Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | UOG Solar | 0 | 0 | 0 | 0 | 0 | 0 |
| 11 | Unbundled RECs | 0 | 0 | 0 | 0 | 0 | 0 |
| 12 | **Total Executed But Not CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 2 through 11] | 0 | 0 | 0 | 0 | 0 | 0 |
| 15 | **CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| 16 | Biogas | 213,398 | 215,310 | 267,185 | 267,182 | 266,495 | 266,549 |
| 17 | Biomass | 3,040,682 | 2,872,745 | 2,656,538 | 2,351,353 | 1,955,668 | 1,217,664 |
| 18 | Geothermal | 3,940,027 | 3,846,522 | 3,835,023 | 2,319,523 | 2,318,615 | 2,324,132 |
| 19 | Small Hydro | 1,055,888 | 919,433 | 830,771 | 756,106 | 709,157 | 612,327 |
| 20 | Solar PV | 6,034,952 | 6,312,897 | 7,174,123 | 7,238,882 | 7,581,317 | 7,738,139 |
| 21 | Solar Thermal | 1,780,838 | 1,783,858 | 1,780,838 | 1,780,838 | 1,780,838 | 1,783,858 |
| 22 | Wind | 4,355,465 | 4,118,960 | 4,026,183 | 3,970,422 | 3,765,438 | 3,760,565 |
| 23 | UOG Small Hydro | 1,251,112 | 1,151,280 | 1,361,309 | 1,433,494 | 1,457,994 | 1,470,682 |
| 24 | UOG Solar | 343,053 | 329,694 | 327,253 | 325,551 | 323,857 | 322,886 |
| 25 | Unbundled RECs | 100,000 | 0 | 0 | 0 | 0 | 0 |
| 26 | **Total CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 16 through 25] | 22,115,415 | 21,550,699 | 22,259,225 | 20,443,351 | 20,159,379 | 19,496,804 |

## Appendix D – Procurement Information Related to Cost Quantification

### Joint IOU Cost Quantification Table 4 (continued)
### (Forecast Generation, MWh)

| | | Forecasted Future RPS-Deliveries 2021-2030 (MWh) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Executed But Not CPUC-Approved RPS-Eligible Contracts** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| 2 | Biogas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | Biomass | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4 | Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5 | Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 6 | Solar PV | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | Solar Thermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | UOG Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | UOG Solar | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 11 | Unbundled RECs | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 12 | **Total Executed But Not CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 2 through 11] | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 15 | **CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| 16 | Biogas | 265,270 | 265,284 | 264,803 | 261,746 | 256,235 | 251,874 | 251,827 | 252,519 | 240,795 | 238,613 |
| 17 | Biomass | 1,090,072 | 1,090,072 | 1,090,072 | 1,092,821 | 1,090,072 | 1,087,042 | 882,505 | 851,855 | 849,722 | 849,722 |
| 18 | Geothermal | 2,316,815 | 152,229 | 151,342 | 150,941 | 149,584 | 148,713 | 147,846 | 147,454 | 146,129 | 145,278 |
| 19 | Small Hydro | 498,763 | 413,322 | 392,430 | 391,039 | 384,319 | 383,913 | 383,483 | 378,818 | 333,264 | 328,828 |
| 20 | Solar PV | 7,724,673 | 7,675,085 | 7,626,096 | 7,593,239 | 7,529,116 | 7,481,119 | 7,433,449 | 7,401,497 | 7,320,714 | 7,267,509 |
| 21 | Solar Thermal | 1,780,838 | 1,780,838 | 1,780,838 | 1,783,858 | 1,780,838 | 1,780,838 | 1,780,838 | 1,783,858 | 1,780,838 | 1,780,838 |
| 22 | Wind | 3,640,391 | 3,525,985 | 3,252,513 | 2,997,365 | 2,968,807 | 2,451,353 | 2,451,353 | 2,455,346 | 2,035,428 | 2,024,985 |
| 23 | UOG Small Hydro | 1,467,619 | 1,467,824 | 1,467,546 | 1,470,461 | 1,466,095 | 1,468,461 | 1,466,608 | 1,471,677 | 1,463,931 | 1,468,041 |
| 24 | UOG Solar | 320,496 | 318,829 | 317,170 | 316,219 | 313,879 | 312,246 | 310,622 | 309,691 | 307,399 | 305,800 |
| 25 | Unbundled RECs | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 26 | **Total CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 16 through 25] | 19,104,938 | 16,689,467 | 16,342,810 | 16,057,689 | 15,938,944 | 15,365,560 | 15,108,532 | 15,052,716 | 14,478,219 | 14,409,613 |

APPENDIX E

RPS-Eligible Contracts Expiring 2015-2025

August 4, 2015

# Appendix E – RPS–Eligible Contracts Expiring 2015–2025

| Log Number | Project Name | Facility Name | Contract Expiration Year | MW | Expected Annual Generation (GWh) | Contract Type | Resource Type | City | State |
|---|---|---|---|---|---|---|---|---|---|
| 01W004 | Green Ridge Power LLC (110 MW) | Green Ridge Power LLC (110 MW) | 2015 | 144.1 | NA | Qualifying Facility (QF) | Wind | Livermore | CA |
| 01W018 | Green Ridge Power LLC (5.9 MW) | Green Ridge Power LLC (5.9 MW) | 2015 | 5.9 | NA | Qualifying Facility (QF) | Wind | Tracy | CA |
| 01W035 | Green Ridge Power LLC (70 MW) | Green Ridge Power LLC (70 MW) | 2015 | 54 | NA | Qualifying Facility (QF) | Wind | Tracy | CA |
| 01W146A | Green Ridge Power LLC (100 MW – A) | Green Ridge Power LLC (100 MW – A) | 2015 | 43.1 | NA | Qualifying Facility (QF) | Wind | Tracy | CA |
| 01W146D | Green Ridge Power LLC (100 MW – D) | Green Ridge Power LLC (100 MW – D) | 2015 | 15 | NA | Qualifying Facility (QF) | Wind | Tracy | CA |
| 04H061QPA2 | Indian Valley Hydro (PURPA) | Indian Valley Hydro | 2015 | 3 | 13.11875 | QF/CHP Summit | Hydro: Small | Clearlake Oaks | CA |
| 10G012QPA | Amedee Geothermal Venture 1 PURPA | Amedee Geothermal Venture 1 | 2015 | 0.69 | 3.5 | QF/CHP Summit | Geothermal | Wendel | CA |
| 16W011 | Green Ridge Power LLC (23.8 MW) | Green Ridge Power LLC (23.8 MW) | 2015 | 10.8 | NA | Qualifying Facility (QF) | Wind | Tracy | CA |
| 16W014 | Altamont Power LLC (3-4) | Altamont Power LLC (3-4 ) | 2015 | 4.05 | NA | Qualifying Facility (QF) | Wind | Tracy | CA |
| 16W015 | Altamont Power LLC (4-4) | Altamont Power LLC (4-4) | 2015 | 19 | NA | Qualifying Facility (QF) | Wind | Tracy | CA |
| 16W028 | Patterson Pass Wind Farm LLC | Patterson Pass Wind Farm | 2015 | 22 | NA | Qualifying Facility (QF) | Wind | Tracy | CA |
| 25C013 | Covanta Mendota L. P. | Mendota Biomass Power | 2015 | 25 | NA | Qualifying Facility (QF) | Biomass | Mendota | CA |
| 04P010 | Gas Recovery Sys. (American Cyn) | American Canyon | 2016 | 1.5 | NA | Qualifying Facility (QF) | Biogas Generation | American Canyon | CA |
| 10C003 | Collins Pine | Collins Pine | 2016 | 12 | NA | Qualifying Facility (QF) | Biomass | Chester | CA |
| 10H002 | Lassen Station Hydro | Lassen Station Hydro | 2016 | 0.99 | NA | Qualifying Facility (QF) | Hydro: Small | Oroville | CA |
| 10H013 | Hypower, Inc. | Hypower, Inc. | 2016 | 10.8 | NA | Qualifying Facility (QF) | Hydro: Small | De Sabla | CA |
| 12H006 | Yuba County Water Agency (Fish Release) | Yuba County Water Agency (Fish Release) | 2016 | 0.15 | NA | Qualifying Facility (QF) | Hydro: Small | Dobbins | CA |
| 13H008 | Arbuckle Mountain Hydro | Arbuckle Mountain Hydro | 2016 | 0.3 | NA | Qualifying Facility (QF) | Hydro: Small | Platina | CA |
| 13H014 | Mega Renewables (Roaring Crk) | Roaring Crk | 2016 | 2 | NA | Qualifying Facility (QF) | Hydro: Small | Montgomery Creek | CA |
| 13H040 | Tko Power (South Fork Bear Creek) | South Fork Bear Creek | 2016 | 3 | NA | Qualifying Facility (QF) | Hydro: Small | Shingletown | CA |
| 13H125 | Mega Hydro #1 (Clover Creek) | Mega Hydro #1 (Clover Creek) | 2016 | 1 | NA | Qualifying Facility (QF) | Hydro: Small | Oak Run | CA |
| 16H003 | Tri-Dam Authority | Tri-Dam Authority | 2016 | 16.2 | NA | Qualifying Facility (QF) | Hydro: Small | Strawberry | CA |
| 16W017 | Altamont Power LLC (6-4) | Altamont Power LLC (6-4) | 2016 | 19 | NA | Qualifying Facility (QF) | Wind | Tracy | CA |
| 33R009 | Diablo Winds | Diablo Winds | 2016 | 18 | 65 | RPS | Wind | Livermore | CA |
| 04H011 | Far West Power Corporation | Far West Power Corporation | 2017 | 0.4 | NA | Qualifying Facility (QF) | Hydro: Small | Potter Valley | CA |
| 06W148 | Edf Renewable Windfarm V, Inc. (10 MW) | EDF Renewable Windfarm V, Inc. (10 MW) | 2017 | 10 | NA | Qualifying Facility (QF) | Wind | Suisun City | CA |
| 13C038 | Burney Forest Products | Burney Facility | 2017 | 31 | NA | Qualifying Facility (QF) | Biomass | Burney | CA |
| 13H001 | El Dorado Hydro LLC (Montgomery Creek) | El Dorado Irrigation District | 2017 | 2.6 | NA | Qualifying Facility (QF) | Hydro: Small | Pollock Pines | CA |
| 13H015 | Mega Renewables (Hatchet Crk) | Hatchet Crk | 2017 | 7 | NA | Qualifying Facility (QF) | Hydro: Small | Montgomery Creek | CA |
| 13H017 | Mega Renewables (Bidwell Ditch) | Bidwell Ditch | 2017 | 2 | NA | Qualifying Facility (QF) | Hydro: Small | Burney | CA |
| 13H036 | Mega Renewables (Silver Springs) | Silver Springs | 2017 | 0.6 | NA | Qualifying Facility (QF) | Hydro: Small | Big Bend | CA |
| 16P002 | Pacific-Ultrapower Chinese Station | Ogden Power Pacific, Inc. (Chinese Station) | 2017 | 22 | NA | Qualifying Facility (QF) | Biomass | Jamestown | CA |
| 19P005 | DG Fairhaven Power, LLC | DG Fairhaven Power, LLC | 2017 | 17.25 | NA | Qualifying Facility (QF) | Biomass | Fairhaven | CA |
| 33R012 | Buena Vista | Buena Vista Energy | 2017 | 43 | 108 | RPS | Wind | Byron | CA |
| 33R252 | PCWA (RPS) – French Meadows / Oxbow / Hell Hole | Multiple | 2017 | 24.6 | 93 | RPS | Hydro: Small | Multiple | Multiple |
| 06W146C | Edf Renewable Windfarm V, Inc. (70 MW – C) | EDF Renewable Windfarm V, Inc. (70 MW – C) | 2018 | 6.5 | NA | Qualifying Facility (QF) | Wind | Suisun City | CA |
| 08H013 | Santa Clara Valley Water Dist. | Santa Clara Valley Water Dist. | 2018 | 0.8 | NA | Qualifying Facility (QF) | Hydro: Small | Morgan Hill | CA |
| 13H042 | Nelson Creek Power Inc. | Nelson Creek Power Inc. | 2018 | 1.1 | NA | Qualifying Facility (QF) | Hydro: Small | Big Bend | CA |
| 13P045 | Wheelabrator Shasta | Wheelabrator Shasta | 2018 | 54.9 | NA | Qualifying Facility (QF) | Biomass | Anderson | CA |
| 25W105 | International Turbine Research | International Turbine Research | 2018 | 34 | NA | Qualifying Facility (QF) | Wind | Pacheco Pass | CA |
| 33R038 | Wadham Energy LP | Wadham | 2018 | 26.5 | 141 | RPS | Biomass | Williams | CA |
| 10H010 | Five Bears Hydroelectric | Five Bears Hydroelectric | 2019 | 0.99 | NA | Qualifying Facility (QF) | Hydro: Small | Genesee Valley | CA |
| 10P005 | HL Power | HL Power | 2019 | 32 | NA | Qualifying Facility (QF) | Biomass | Wendel | CA |
| 12H007 | Sts Hydropower (Kanaka) | STS Hydropower Ltd. (Kanaka) | 2019 | 1.1 | NA | Qualifying Facility (QF) | Hydro: Small | Oroville | CA |
| 13H024 | Olsen Power Partners | Olsen Power Partners | 2019 | 5 | NA | Qualifying Facility (QF) | Hydro: Small | Whitmore | CA |
| 15H005 | Eif Haypress LLC (LWR) | Haypress Hydroelectric, Inc. (LWR) | 2019 | 6.1 | NA | Qualifying Facility (QF) | Hydro: Small | Sierra City | CA |
| 15H006 | Eif Haypress LLC (Mdl) | Haypress Hydroelectric, Inc. (MDL) | 2019 | 8.7 | NA | Qualifying Facility (QF) | Hydro: Small | Sierra City | CA |
| 25H037 | Friant Power Authority | Friant Power Authority | 2019 | 25 | NA | Qualifying Facility (QF) | Hydro: Small | Friant | CA |
| 25H073 | Olcese Water District | Kern Hydro (Olcese) | 2019 | 16 | NA | Qualifying Facility (QF) | Hydro: Small | Bakersfield | CA |
| 25P026 | Rio Bravo Fresno | Rio Bravo Fresno | 2019 | 26.5 | NA | Qualifying Facility (QF) | Biomass | Fresno | CA |
| 33R054 | Klondike IIIA | Klondike IIIA Wind Power | 2019 | 90 | 263.258 | RPS | Wind | Wasco | OR |
| 33R061AB | Castelanelli Bros. Biogas | Castelanelli Bros. | 2019 | 0.3 | 1.3 | AB1969/FiT | Biogas Generation | Lodi | CA |
| 33R101AB | Snow Mountain Hydro (Lost Creek 1) – Contract | Lost Creek 1 | 2019 | 1.1 | 9.636 | AB1969/FiT | Hydro: Small | Hat Creek | CA |
| 33R102AB | Snow Mountain Hydro (Lost Creek 2) – Contract | Lost Creek 2 | 2019 | 0.5 | 4.38 | AB1969/FiT | Hydro: Small | Hat Creek | CA |
| 12H010 | Deadwood Creek (Hydro Sierra Energy, LLC) | Deadwood Creek (Yuba County Water Agency) | 2020 | 2 | NA | Qualifying Facility (QF) | Hydro: Small | Challenge | CA |
| 13H013 | Snow Mountain Hydro LLC (Cove) | Snow Mountain Hydro (Cove) | 2020 | 5 | NA | Qualifying Facility (QF) | Hydro: Small | Montgomery Creek | CA |
| 13H016 | Snow Mountain Hydro LLC (Burney Creek) | Burney Creek – Amendment | 2020 | 3 | NA | Qualifying Facility (QF) | Hydro: Small | Burney | CA |
| 13H035 | Snow Mountain Hydro LLC (Ponderosa Bailey Creek) | Snow Mountain Hydro (Ponderosa Bailey Creek) | 2020 | 1.1 | NA | Qualifying Facility (QF) | Hydro: Small | Manton | CA |
| 15P028 | Rio Bravo Rocklin | Rocklin Facility | 2020 | 25 | NA | Qualifying Facility (QF) | Biomass | Rocklin | CA |
| 16P054 | Thermal Energy Dev. Corp. | Thermal Energy Dev. Corp. | 2020 | 21 | NA | Qualifying Facility (QF) | Biomass | Tracy | CA |
| 25H149 | Orange Cove Irrigation Dist. | Orange Cove Irrigation Dist. | 2020 | 0.45 | NA | Qualifying Facility (QF) | Hydro: Small | Friant | CA |
| 25H150 | Kings River Hydro Co. | Kings River Hydro Co. | 2020 | 1 | NA | Qualifying Facility (QF) | Hydro: Small | Sanger | CA |
| 33R074 | SFWP (RPS) – Sly Creek / Kelly Ridge | Multiple | 2020 | 23 | 106 | RPS | Hydro: Small | Multiple | Multiple |
| 33R075 | Woodland Biomass | Woodland Biomass | 2020 | 25 | 175 | RPS | Biomass | Woodland | CA |
| 33R096AB | Combie South FiT | Combie South Powerhouse | 2020 | 1.5 | 3.947 | AB1969/FiT | Hydro: Small | Grass Valley | CA |
| 33R141AB | NID Scotts Flat FiT | Scotts Flat Powerhouse | 2020 | 0.85 | 3.203 | AB1969/FiT | Hydro: Small | Nevada City | CA |
| 33R146AB | Blake's Landing – 80kW Generator | 80kW Generator | 2020 | 0.08 | 0.6 | AB1969/FiT | Biogas Generation | Marshall | CA |
| 33R015 | Shiloh I Wind Project | Shiloh I Wind | 2021 | 75 | 225 | RPS | Wind | Birds Landing | CA |
| 33R093 | Geysers – 2010 – 50/250/425 MW | Multiple | 2021 | 250 | 2080 | RPS | Geothermal | Multiple | Multiple |
| 33R140 | El Dorado Irrigation District | Multiple | 2021 | 22 | 99.3 | RPS | Hydro: Small | Multiple | Multiple |
| 33R030 | Klondike III | Klondike III Wind Power | 2022 | 85 | 265 | RPS | Wind | Wasco | OR |
| 33R230AB | Wolfsen Bypass FiT | Wolfsen Bypass | 2022 | 0.98 | 5 | AB1969/FiT | Hydro: Small | Los Banos | CA |
| 33R231AB | San Luis Bypass FiT | San Luis Bypass | 2022 | 0.6 | 3 | AB1969/FiT | Hydro: Small | Los Banos | CA |
| 33R240AB | South Sutter Water FiT | Vanjop No. 1 | 2022 | 0.395 | 2 | AB1969/FiT | Hydro: Small | Sheridan | CA |
| 33R246 | Wind Resource I – RAM 1 | Wind Resource I | 2022 | 8.71 | 15.41 | RPS | Wind | Tehachapi | CA |
| 33R250AB | Browns Valley Irrigation District FiT | Virginia Ranch Dam Powerhouse | 2022 | 1.04 | 5.2 | AB1969/FiT | Hydro: Small | Oregon House | CA |
| 08C078 | City Of Watsonville | City Of Watsonville | 2023 | 0.55 | NA | Qualifying Facility (QF) | Biogas Generation | Watsonville | CA |
| 33R276 | Wind Resource II – RAM 2 | Wind Resource II (1) | 2023 | 19.955 | 46.41 | RPS | Wind | Tehachapi | CA |
| 33R284 | ABEC Bidart-Stockdale LLC | Bidart Dairy III (Stockdale) | 2023 | 0.6 | 1.4 | RPS | Biogas Generation | Bakersfield | CA |
| 33R045 | Rattlesnake Road Wind Power Project | Arlington Wind Power Project – Rattlesnake Road | 2024 | 102.9 | 240 | RPS | Wind | Arlington | OR |
| 33R077AB | Combie North FiT | Combie North Powerhouse | 2024 | 0.5 | 1.316 | AB1969/FiT | Hydro: Small | Grass Valley | CA |
| 33R333RM | Digger Creek Hydro | Digger Creek Hydro | 2024 | 0.65 | 3.5 | AB1969/FiT | Hydro: Small | Manton | CA |
| 33R337RM | Clover Flat LFG | Clover Flat LFG | 2024 | 0.848 | 5.747 | AB1969/FiT | Biogas Generation | Calistoga | CA |
| 33R053AB | Santa Maria II | Santa Maria II LFG Power Plant | 2025 | 1.42 | 12.439 | AB1969/FiT | Biogas Generation | Santa Maria | CA |
| 33R058 | Hatchet Ridge | Hatchet Ridge Wind | 2025 | 103.2 | 303 | RPS | Wind | Burney | CA |
| 33R083 | Vantage Wind Energy Center | Vantage Wind Energy Center | 2025 | 90 | 277 | RPS | Wind | Ellensburg | WA |
| 33R342RM | Water Wheel Ranch | Water Wheel Ranch (SB32) | 2025 | 0.975 | 3.4 | AB1969/FiT | Hydro: Small | Round Mountain | CA |

This Expiring Contract List does not include any projects that are non-operational

APPENDICES F.1 – F.5b

Redacted in Entirety

August 4, 2015

# APPENDIX G

# Other Modeling Assumptions Informing Quantitative Calculation

August 4, 2015

# Appendix G – Other Modeling Assumptions Informing Quantitative Calculation

## Other Modeling Assumptions Informing Quantitative Calculation[1]

| Assumptions Related to Procurement Quantity Requirement | |
|---|---|
| **Compliance Periods** | • As implemented by D.11-12-020, SB 2 1X requires retail sellers of electricity to meet the following RPS procurement quantity requirements beginning on January 1, 2011:<br>  ○ An average of twenty percent of the combined bundled retail sales during the first compliance period (2011-2013).<br>  ○ Sufficient procurement during the second compliance period (2014-2016) that is consistent with the following formula: (.217 * 2014 retail sales) + (.233 * 2015 retail sales) + (.25 * 2016 retail sales).<br>  ○ Sufficient procurement during the third compliance period (2017-2020) that is consistent with the following formula: (.27 * 2017 retail sales) + (.29 * 2018 retail sales) + (.31 * 2019 retail sales) + (.33 * 2020 retail sales).<br>  ○ 33 percent of bundled retail sales in 2021 and all years thereafter.<br>• Under the 40 percent scenario, requirements that are consistent with the following formula: (.33 * 2021 retail sales) + (.37 * 2022 retail sales) + (.37 * 2023 retail sales) + (.40 * 2024 retail sales) and beyond. |
| **Assumptions Related to Forecasted Generation** | |
| **Non-QF Projects**<br><br>*Contracts Executed Post-2002* | • Except for the “OFF/Closely Watched” contract category (see Section 4), all non-QF signed contracts are assumed to deliver at 100% of contract volumes, and deliveries commence within the allowed delay provisions in the contract. |
| **QF Non-Hydro Projects**<br><br>*Contracts Executed Pre-2002* | • Forecast is typically based on an average of the three most recent calendar year deliveries.<br>• Year 2015 deliveries: Recorded meter data replaces forecasted deliveries for all projects as it becomes available. |

1 All assumptions in this table reflect an April 30, 2015 data vintage which is consistent with the data vintage of Appendices C1 – C4.

# Appendix G – Other Modeling Assumptions Informing Quantitative Calculation

<table>
<tr><td>QF Hydro<br><br>Pre-2002 QF, Irrigation District, and Legacy Utility-Owned Assets</td><td><ul><li>Forecast is typically based on historical production, calendar year deliveries, and regularly updated with PG&E’s latest internal hydro updates.</li><li>Projects are forecasted at 48% of average water year generation for 2015 (based on PG&E’s April 30, 2015 vintage internal hydro delivery forecast) and reverting to average water years in later years.</li><li>Year 2015 deliveries: Recorded meter data replaces forecasted deliveries for all projects as it becomes available.</li></ul></td></tr>
<tr><td>Non-QF Hydro<br><br>Utility Owned Generation (UOG) and Irrigation District Water Authority (IDWA)</td><td><ul><li>Forecasts reflect PG&E’s best available projections for hydro conditions.</li><li>Projects are forecasted at 48% of average water year generation for 2015 (based on PG&E’s April 30, 2015 vintage internal hydro delivery forecast) and reverting to average water years in later years.</li><li>Year 2015 deliveries: Recorded meter data replaces forecasted deliveries for all projects as it becomes available.</li></ul></td></tr>
<tr><td>Future Volumes from Pre-Approved Programs</td><td>Feed-in Tariffs<br><br>E-SRG, E-PWF (AB 1969 FIT)<ul><li>All deliveries from executed contracts are assumed at 100% of contract volumes.</li><li>Annual energy volumes (for non-operating projects) are modeled based on PG&E's best estimate for project start dates/initial energy delivery date.</li></ul>ReMAT<ul><li>All deliveries from executed contracts are assumed at 100% of contract volumes.</li><li>Modeled start date for generic volumes assumed to begin 7/1/2016 and ramp up linearly until 1/1/2019, reaching a total of ~114 MW.</li></ul>SB1122 (Bioenergy Feed-in Tariff Program)<ul><li>Modeled start date for generic volumes assumed to begin 7/1/2017 and ramp up linearly until 7/1/2021, reaching a total of ~111 MW.</li></ul>Renewable Auction Mechanism (Remaining Capacity)<ul><li>For planning purposes PG&E assumed a project start date equal to 12/1/2017.</li><li>Technology mix assumed to be 32 MW of as-available peaking.</li></ul></td></tr>
</table>

| | |
|---|---|
| | • All deliveries from executed contracts are assumed at 100% of contract volumes.<br><br>**PV Originally Authorized for PG&E Photovoltaic Program**<br>• Consistent with PG&E's February 26, 2014 Petition for Modification (PFM)[2] requesting to terminate the PV Program and modify the RAM Decision process to procure the remaining PV Program volumes using RAM solicitation processes PG&E assumed that the Renewable Auction Mechanism accommodates the remaining 200 MW of PG&E's PV Program volumes.<br>• For planning purposes, PG&E has assumed that a total of 209 MW will be coming online between 2017 and 2018.[3]<br>• All deliveries from executed contracts are assumed at 100% of contract volumes. |
| **Re-contracting** | • For the following reasons this risk-adjusted forecast does not assume that expiring volumes are retained:<br>1. PG&E does not yet have contractual commitments for these expiring volumes;<br>2. A number of the expiring contracts are with aging generating facilities with limited remaining useful life;<br>3. Contract-renewal bids may not be competitive with offers for new projects received in future solicitations; and<br>4. Assuming re-contracted volumes obscures PG&E's current real need for additional energy in later years.<br>• Re-contracting is not precluded by this assumption, but rather it reflects that re-contracting will be considered in the future side-by-side with procurement of other new resources.<br>• This forecasting methodology (i.e. not assuming any re-contracting) is consistent with PG&E's Annual RPS compliance filing that only shows PG&E's current contractual commitments. |
| **Shortlisted Projects**<br><br>*From 2014 Solicitation or Bilateral Offer* | • No shortlisted projects are included in PG&E's forecast.<br>• Only executed contracts, or generic deliveries from pre-approved procurement programs (i.e., RAM, Feed-in Tariffs, etc.) are included in PG&E's forecast. |

2 Advice Letter 3809-E. http://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/RAM/ELEC_3809-E.pdf.

3 This assumption is based on a modeling vintage of April 2015.

## Appendix G – Other Modeling Assumptions Informing Quantitative Calculation

| | |
|---|---|
| **Green Tariff Shared Renewables (GTSR)** | • If the Commission approves PG&E's pending advice letters to implement GTSR Program, PG&E plans to allocate small amounts of generation from RPS-eligible resources to serve initial GTSR enrollees until new incremental resources procured for the GTSR program are sufficient to meet program needs.<br>• Once the GTSR program is underway, PG&E would also incorporate any GTSR related impacts on its RPS compliance position into future updates to its RNS. |
| **Banking** | • PG&E assumes that (1) Category 3 products that do not exceed applicable portfolio content limits are not deducted from bankable volumes, (2) grandfathered (pre-June 1, 2010) short-term products are bankable, and (3) that banked volumes may be applied in any period onward.<br>• PG&E's accounting is consistent with the direction set forth in Decision 12-06-038. |
| **RPS Sales** | • PG&E will continue to assess the value to its customers of sales of surplus procurement. Currently, PG&E's renewable net short (RNS), future RPS cost projections and assessment of the current REC market does not lead to an expectation of material projected sales of RECs. However, PG&E will consider selling surplus non-bankable RPS volumes and may consider selling surplus bankable volumes if it can still maintain an adequate Bank and if market conditions are favorable. PG&E will update its RNS if it executes any such agreements. |

# Appendix G – Other Modeling Assumptions Informing Quantitative Calculation

| Assumptions Related to Forecasted Sales | |
|---|---|
| **Bundled Retail Sales**<br>*RNS (App. C1 and C3)* | • Forecasts of retail sales for the first five years of the forecast were generated by PG&E's *Load Forecasting and Research* team in April 2015, and may be updated throughout the year as additional data becomes available.<br>• Forecasts of retail sales beyond the first five years are sourced from the latest LTPP standardized planning assumptions, per the May 21, 2014 ALJ Ruling in R.11-05-005 regarding the methodology for calculating the renewable net short.<br>• Monthly recorded sales replace forecasts as 2015 progresses. |
| **Bundled Retail Sales**<br><br>*Alternate RNS*<br>*(App. C2 and C4)* | • Forecasts of retail sales were generated by PG&E's *Load Forecasting and Research* team in April 2015, and may be updated throughout the year as additional data becomes available.<br>• Monthly recorded sales replace forecasts as 2015 progresses. |

# APPENDIX H

## Responses to Renewable Net Short Questions

August 4, 2015

# Appendix H - Responses to Renewable Net Short Questions

The following presents PG&E's responses to questions set forth in the May 21, 2014 *Administrative Law Judge's Ruling on Renewable Net Short*.

## RPS Compliance Risk

**1. How do current and historical performance of online resources in your RPS portfolio impact future projections of RPS deliveries and your subsequent RNS?**

PG&E considers historical performance of online resources in both of its models. First, it considers this performance in developing the generation forecast in its deterministic model. As discussed in Appendix G, future projections of RPS deliveries in the deterministic model are based on a blended three year average output for QF contracts.

In addition, within its stochastic model, PG&E considers RPS generation variability based on historical performance of each resource type. A probabilistic distribution is built for each resource based on its calculated coefficient of variation. This captures additional RPS generation variability above and beyond the variances that are captured in the deterministic model. Section 6.2.2 of the RPS Plan describes in more detail how historic generation variability from each resource is used as an input to the stochastic model.

**2. Do you anticipate any future changes to the current bundled retail sales forecast? If so, describe how the anticipated changes impact the RNS.**

PG&E's retail sales are impacted by many factors, including weather, economic growth or recession, technological change, energy efficiency, DA and CCA participation levels, and distributed generation. PG&E's most recent Sales Forecast used in the RPS Plan is an April 2015 updated version of the Alternate Scenario Forecast used in the 2014 Bundled Procurement Plan submitted in October 2014 in Rulemaking 13-12-010. It is important to emphasize that PG&E's Alternative Scenario is a forecast including a number of assumptions regarding events which may or may not occur. PG&E updates the bundled load forecasts annually to reflect any new events and capture actual load changes. As described in more detail in Section 6.2.1, PG&E uses its stochastic model to simulate a range of potential retail sales forecasts. Changes in retail sales tend to be variable and persistent, [redacted], particularly over time. However, PG&E's modeling results presented in Section 7 are robust to future changes in sales.

**3. Do you expect curtailment of RPS projects to impact your projected RPS deliveries and subsequent RNS?**

To the extent that RPS projects are economically bid and do not clear the market, or are curtailed for system reliability, PG&E expects that curtailment will impact its RNS. As described in Sections 6.2.3 and 11, the stochastic model evaluates uncertainty associated with RPS generation variability, including assumptions of future levels of RPS curtailment.

**4. Are there any significant changes to the success rate of individual RPS projects that impact the RNS?**

PG&E assumes a volumetric success rate for all executed in-development projects in its RPS portfolio of approximately 99% of total contracted volumes. This rate continues its general trend of increasing from 60% in RPS Plans prior to 2012, to 78% in PG&E's 2012 RPS Plan, to 100% in PG&E's 2013 RPS Plan, and 87% in PG&E's 2014 RPS Plan. This success rate is evolving and highly dependent on the nature of PG&E's portfolio and the general conditions in the renewable energy industry. While PG&E has continued to see a general trend towards higher project success rates, its revised success rate assumption (from 87% to 99%) reflects the recent removal of several projects from PG&E's portfolio due to contract termination and an update to the "Closely Watched" category described in Section 6.

In addition, to model the project failure variability inherent in project development, PG&E adds additional success rate assumptions to it stochastic model, which assume that project viability for a yet-to-be-built project is a function of the number of years until its contract start date. These assumptions are used in order to calculate its stochastically-optimized net short (SONS). See the answer to question #5 below for details on these new assumptions.

**5. As projects in development move towards their COD, are there any changes to the expected RPS deliveries? If so, how do these changes impact the RNS?**

Yes. PG&E may adjust the expected delivery volumes in its deterministic model for RPS projects in development for various reasons. For example, counterparties may make adjustments to their project design, such as decreasing total project capacity, which may lead to changes in expected generation. Counterparties may also experience project delays which impact the delivery date for projects, shifting generation volumes further into the future. In extreme cases, as described in Section 6.1.2, PG&E may categorize projects experiencing considerable development challenges as "Closely Watched" and would in those cases reduce the expected delivery volumes from those projects to zero in its deterministic model. Moving a project to the "Closely Watched" category would therefore decrease future delivery volumes and increase the RNS. PG&E has an extensive program for monitoring the development status of RPS-eligible projects, and the deterministic model is updated regularly to reflect any relevant status changes.

In addition, PG&E further reduces its anticipated deliveries from future projects in its stochastic model, as described in more detail in Section 6.2.4. To model the project

failure variability inherent in project development, PG&E assumes that project viability for a yet-to-be-built project is a function of the number of years until its contract start date. PG&E assigns a probability of project success for new, yet-to-be-built projects equal to [redacted].
For example, a project scheduled to come online in five years or more is assumed to have a [redacted] or [redacted] chance of success. This success rate is based on experience, and although PG&E's current existing portfolio of projects may have higher rates of success, the actual success rate for projects in the long-term may be higher or lower. Appendices F.2a and F.2b show PG&E's simulated failure rate and for the period 2015-2030 in the 33% RPS and 40% RPS, respectively.

**SUMMARY:**
**COMPARISON OF UNCERTAINTY ASSUMPTIONS**
**BETWEEN PG&E'S DETERMINISTIC AND STOCHASTIC MODELS**

| Reference Above and Uncertainty it Represents | Deterministic Model | Stochastic Model |
|---|---|---|
| **Question #2:** Retail Sales Variability | Uses most recent PG&E bundled retail sales forecast for next 5 years and 2014 LTPP for later years. | Distribution based on most recent (2015) PG&E bundled retail sales forecast. |
| **Question #4 and #5:** Project Failure Variability | Only turns "off" projects with high likelihood of failure per criteria. "On" projects assumed to deliver at Contract Quantity. | Uses [redacted] to model a success rate for all "on" yet-to-be-built projects in the deterministic model. Thus, for a project scheduled to come online in 5 years, the project success rate is [redacted]. This success rate is based on PG&E's experience that the further ahead in the future a project is scheduled to come online, the lower the likelihood of project success. Re-contracted projects are assumed to have a [redacted] success rate. |
| **Question #1:** RPS Generation Variability | Non-QF projects executed post-2002, 100% of contracted volumes<br>For non-hydro QFs, typically based on an average of the three most recent calendar year deliveries<br><br>Hydro QFs, UOG and IDWA generation projections are updated to reflect the most recent hydro forecast. | Hydro: [redacted] annual variation<br>Wind: [redacted] annual variation<br>Solar: [redacted] annual variation<br>Biomass and Geothermal: [redacted] annual variation |
| **Question #3: Curtailment**[1] | None | 33% Scenario: [redacted] of RPS requirement<br>40% Scenario: [redacted] of RPS requirement through 2021, increasing to [redacted] in 2024 and beyond. |

1 These modeling assumptions will not necessarily align with the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance. Please see Section 11 for more information.

**6. What is the appropriate amount of RECs above the PQR to maintain? Please provide a quantitative justification and elaborate on the need for maintaining banked RECs above the PQR.**

As described in Sections 6 and 7, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in the stochastic model. PG&E performed a simulation of variability in PG&E's future generation and RPS compliance targets over [redacted] years—i.e., the amount of RPS generation ("delivery") net of RPS compliance targets ("target")—and found that a Bank size of at least [redacted] GWh is the minimum Bank necessary to maintain a cumulative non-compliance risk of no greater than [redacted]. Under a 40% by 2024 scenario and current market assumptions, PG&E would plan to maintain a minimum Bank level of at least [redacted] GWh. However, because the stochastic model inputs change over time, forecasts of the Bank size will also change, so these estimates should be seen as a point forecast rather than a static target. Please see Section 6 for additional information.

**7. What are your strategies for short-term management (10 years forward) and long-term management (10-20 years forward) of RECs above the PQR? Please discuss any plans to use RECs above the PQR for future RPS compliance and/or to sell RECs above the PQR.**

As described in Sections 6 and 7, PG&E uses its stochastic model to optimize its procurement. This model currently forecasts Bank levels through [redacted], projecting that PG&E's forecasted Bank size [redacted] GWh by [redacted]. Under this projection, [redacted] Bank will be maintained as VMOP to manage additional risks and uncertainties associated with managing an RPS portfolio.

In the long-term, PG&E will use RECs above the PQR, as needed, to maintain an adequate Bank, as determined by the deterministic and stochastic model or similar means, in order to manage additional risks and uncertainties.

PG&E's optimization strategy includes consideration of sales of surplus procurement. Consistent with the Commission-approved RNS, PG&E's physical net short and cost projections do not include any future projected sales of bankable contracted deliveries. However, PG&E will consider selling surplus non-bankable RPS volumes and may consider selling surplus bankable RPS volumes if it can still maintain adequate Bank and if market conditions are favorable. As PG&E encounters economic opportunities to sell volumes, PG&E will use the stochastic model to help evaluate whether the proposed sale will increase the cumulative non-compliance risk for [redacted].

## VMOP

**8. Provide VMOP on both a short-term (10 years forward) and long-term (10-20 years forward) basis. This should include a discussion of all risk factors and a quantitative justification for the amount of VMOP.**

As discussed in Sections 6 and 7, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in the stochastic model. [redacted], PG&E believes it would be imprudent to use its entire projected Bank toward meeting the 33% RPS target or 40% RPS scenario, rather than to cover unexpected demand and supply variability and project failure or delay exceeding forecasts from projects not yet under contract. When used as VMOP, the Bank will help to avoid long-term over-procurement above the 33% target, and will thus reduce long-term costs of the RPS Program.

**9. Please address the cost-effectiveness of different methods for meeting any projected VMOP procurement need, including application of forecast RECs above the PQR.**

As discussed in Sections 6 and 7, PG&E's stochastic model optimizes its results to inform its RPS procurement strategy, which includes using a portion of the Bank as VMOP, to achieve the lowest cost possible given a specified risk of non-compliance. The model suggests a specific level of procurement and resulting Bank usage for each year. PG&E then uses these model results as a tool to guide its actual procurement strategy. While the model provides other possible VMOP usage given a specific level of non-compliance risk, these paths would not be minimum cost under the model's assumptions.

As a general matter, PG&E does not approach RPS procurement and compliance as a speculative enterprise and so has not modeled or otherwise proposed such strategies in this Plan. However, PG&E will consider selling surplus non-bankable RPS volumes in its portfolio and, in doing so, may seek to sell surplus bankable volumes if it can still maintain an adequate Bank and if market conditions are favorable.

## Cost-Effectiveness

**10. Are there cost-effective opportunities to use banked RECs above the PQR for future RPS compliance in lieu of additional RPS procurement to meet the RNS?**

As discussed in greater detail in Sections 6, 7, and 8 of this Plan, [redacted]. As long as PG&E can continue to maintain an adequate Bank that does not jeopardize PG&E's ability to manage its non-compliance risk and thus avoid being caught in a "seller's market," where PG&E would face potentially high market prices in order to meet near-term compliance deadlines.

Overall, PG&E can best meet the objective to minimize customer costs when it can thoroughly examine and take advantage of all cost-effective commercial opportunities to purchase or sell RPS-eligible products consistent with its RPS Plan on a going-forward basis, continually adapting to these uncertain variables. PG&E will continue to use the stochastic model to help guide decisions around minimum Bank size needed to maintain PG&E's non-compliance risk of [redacted] for the period of [redacted]. PG&E will then procure any needed incremental volumes ratably over time.

**11. How does your current RNS fit within the regulatory limitations for PCCs? Are there opportunities to optimize your portfolio by procuring RECs across different PCCs?**

PG&E's current RPS portfolio consists of primarily Category 0 and 1 RECs. Category 3 products are a limited, but potentially important, part of PG&E's procurement strategy as they may provide a low-cost compliance option for PG&E's customers while at the same time potentially mitigating integration and other operational challenges associated with incremental procurement from typical Category 1 or Category 2 procurement.

While PG&E seeks opportunities across all product categories to procure the most cost-effective resources to achieve the RPS requirements, the existing restrictions on banking of excess procurement limit PG&E's ability to fully optimize its portfolio. Under the current RPS rules, short-term contracts cannot count towards excess procurement eligible for banking toward a future RPS compliance period. The result is that any entity that has excess procurement during a particular compliance period is effectively restricted from procuring short-term contracts during that compliance period. Only when an entity does not exceed its compliance period target, is it able to count short-term procurement towards meeting its targets.

PG&E currently maintains a bank in order to help mitigate procurement and load variability. Thus, the inability for short-term contracts to contribute to the bank restricts our mitigation strategy. Allowing the unrestricted banking of all RPS products, including those associated with short-term contracts, would enable PG&E to better manage risks and achieve cost-savings for our customers.